PETROLEUM DEVELOPMENT AND TECHNOLOGY

1949

PETROLEUM BRANCH

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PETROLEUM BRANCH

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FOREWORD

It is indeed a pleasure to view in retrospect the accomplishments of the Petroleum Division in 1948 under the chairmanship of Mr. Alcorn. The decentralization of AIME into three branches, namely, Petroleum, Mining, and Metals, and the delegation of authority to the branches with respect to substantial control of their own publications, are real steps toward strengthening the Institute. The efforts of the Executive Committee and Officers of the Petroleum Division for both 1947 and 1948 are to be highly commended for exercising the leadership that has brought into reality the many years' dreams of petroleum leadership in the AIME.

The Executive Committee and the Officers of the Petroleum Branch for 1949 are blessed with the opportunity to participate in free leadership, but at the same time they face a real challenge to help build the foundation of what has the right to be a new era of AIME service to its membership.

At the 77th Annual Meeting, held in San Francisco, "Certificates of Service" were awarded to F. Julius Fohs, Houston, and J. B. Umpleby, Dallas, in acknowledgment of their exceptional services to members of the Petroleum Branch. Also, Mr. Robert L. Hoss, Houston, was awarded The Alfred Noble Prize for 1948 for his outstanding paper, "Calculated Effect of Pressure Maintenance on Oil Recovery."

We are proud to announce the formation of the Kansas Section and to advise that the number of AIME members affiliated through the Petroleum Branch was increased 504 during the year.

It is a known fact that the Petroleum Branch of AIME is the standard bearer for petroleum technology in the fields of production, research, and economics. It is hoped that each member will do all within his power to advance this standard. We can all assist in this challenge by getting together and discussing our mutual problems and exploring areas on conflict. The organization of topical study groups within several local sections has done much to generate open-minded thinking and ultimately the solution of many technologic problems vital to our industrial progress along the lines of conservation. May it never be said that the petroleum engineering profession has failed to serve well its common cause with our American economy and our community at large.

Lloyd E. Elkins, *Chairman,*
Petroleum Division, 1949.

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CONTENTS

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THE ANTHONY F. LUCAS FUND AND MEDAL

In 1936 the Institute established the Anthony F. Lucas Gold Medal, to be awarded from time to time "for distinguished achievement in improving the technique and practice of finding and producing petroleum." These awards are sponsored by the Petroleum Branch.

Captain Lucas was a pioneer in the oil industry, one of the early wildcatters and a leading mining and petroleum engineer. He was famous as the discoverer of Spindletop. He became a member of the Institute in 1895 and in 1913 was the first Chairman of the Petroleum and Gas Committee of the Institute, the forerunner of the present Petroleum Branch. He also headed the Committee in 1914, 1917 and 1918.

Medals Awarded

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Henry L. Doherty, February 1938
E. DeGolyer, February 1940
Conrad (posthumously) and Marcel Schlumberger, February 1941
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CHAPTER I. *Marine Drilling*

Wave Action on Structures

BY WALTER H. MUNK*

(Tulsa and Los Angeles Meetings, October 1947)

ABSTRACT

GENERATION of waves by storms, and the transformation of waves in shallow water by local bottom topography are briefly reviewed. A detailed description of water motion in waves explains the nature and distribution of wave forces. A numerical example dealing with forces and moments against vertical piles summarizes the principles involved.

INTRODUCTION

The oil industry is moving into the open waters of the Gulf of Mexico. The design and construction of offshore drilling rigs present a number of difficult problems, among them problems involving the action of waves on fixed and floating structures. This paper deals with our present knowledge of ocean waves as it pertains to these problems, and the principles involved in computing wave forces against fixed structures. It is hoped that the more difficult case pertaining to floating structures can be discussed at a later time. None of the engineering aspects of the problem are entered upon in this paper, yet an understanding of the principles presented here should be helpful in the solution of practical problems.

Contribution from the Scripps Institution of Oceanography, New Series No. 352. This work represents results of research carried out for the Hydrographic Office, the Office of Naval Research, and the Bureau of Ships of the Navy Department under contract with the University of California.

Manuscript received at the office of the Institute Nov. 4, 1947. Issued as TP 2322 in PETROLEUM TECHNOLOGY, March 1948.

* Institute of Geophysics and Scripps Institution of Oceanography, University of California.

NATURE OF WAVE FORCES

Waves are capable of exerting almost unbelievable forces. During a gale, waves at the harbor entrance of Amsterdam Canal in Holland lifted a 20-ton concrete block, which was resting on the bottom in 12 ft of water, and deposited it on top of a pier which was 5 ft above the high water mark. At Wick Breakwater in Scotland, a mass of large stones in cement and bound together with iron rods, weighing 1350 tons, was broken loose and moved bodily! But one need not go to Holland or Scotland to find evidence of damage that waves are capable of inflicting (Fig 1 and 2).

What is the mechanism by which waves are capable of exerting such enormous forces? To answer this, we must consider briefly the nature of wave motion. When a wind blows over a wheat field, waves appear to travel across the field, whereas the wheat itself remains rooted, slowly swinging back and forth. Similarly, in the case of water waves, the wave *form* travels swiftly over the water surface, whereas the water particles oscillate back and forth, but scarcely advance. The speed of the wave form is called *wave velocity*, the speed of the water particles is called *orbital velocity*. This fundamental difference between wave velocity and orbital velocity was already recognized by Leonardo da Vinci. Orbital velocity is generally much slower than wave velocity except for a breaking wave, a case which is of particular importance in the application to engineering problems.

Forces exerted by the waves on obstacles

are primarily due to the orbital motion. Since the orbital motion is oscillatory, moving once with the waves and then in the opposite direction, the forces themselves are oscillatory. However, at any given instant the forces exerted will be the same,

FIG 1—HURRICANE-DRIVEN WAVE TOWERING MANY FEET IN THE AIR SMASHES AT THE APPROACH TO A BRIDGE JUST NORTH OF MIAMI BEACH, FLA., SEPTEMBER 19, 1947. (Photograph by Acme Newspictures)

or nearly the same, as would be exerted on this obstacle if it were placed into a stream of uniform motion equal in speed to that of the orbital motion. An exception to this would occur if the resonance frequency of the entire structure would be close to the wave frequency, and the structure be set into violent vibrations.

The dynamic pressure exerted by water moving uniformly past obstacles has been studied extensively, and the resulting law is well known in engineering practice:

$$P = \frac{C_D}{2} \frac{w}{g} V^2 \qquad [1]$$

P is the pressure in pounds per square foot; C_D the drag coefficient; w the weight in pounds of a cubic foot of water (65 lb for sea water); g the acceleration due to gravity in feet per square second; and V the velocity of water in feet per second past the obstacle. The ratio $w/g = 2$ approximately, and the equation can be written

$$P = C_D V^2 \qquad [2]$$

The drag coefficient C_D depends upon the shape of the obstacle and on Reynolds' number R where, with D designating the effective diameter,

$$R = \frac{VD}{\nu} \qquad [3]$$

For water of about 70°F, the kinematic viscosity $\nu = 10^{-5}$ ft² per sec, so that R can be written $R = 10^5 VD$. For most structures subject to wave action the product VD will be considerably larger than 5 ft² per

sec, and consequently $R > 5 \times 10^5$, indicating fully developed turbulent flow.

The values of Table 1 are selected from Table II of Rouse.[1]

The pressure exerted by waves on pier

FIG 2—CLOSE-UP OF DAMAGE CAUSED BY WAVES SHOWN IN FIG 1.
(Photograph by Acme Newspictures)

piles of |——|-section (assumed similar to rectangular plates) will be at least six times the pressure exerted on cylindrical

TABLE 1—*Approximate Values of the Drag Coefficient C_D*

Form of Body	R	C_D
Circular disc ⊥ to flow.........	$>10^3$	1.12
Long rectangular plate ⊥ to flow	$>10^3$	1.90
Long circular cylinder (axis ⊥ to flow).	$>10^5$	1.20
	$> 5 \times 10^5$	0.33
Sphere........................	$>10^5$	0.50
	$> 3 \times 10^5$	0.20

pier piles of similar dimension! Expecting |——|-sections to withstand very large waves is somewhat like expecting a racing automobile housed in a model T chassis to establish a new speed record.

Eq 2 can be checked by comparison with wave pressures measured by Gaillard[2] with dynamometers in Florida and Lake Superior (see Fig 16). Observed and computed values agree within 20 pct. This suggested to Gaillard that the sudden slaps of waves against structures, accompanied by loud noises and spray, are more spectacular than important, and that the truly destructive forces are due to the relatively sustained orbital motion of the water against obstacles. The pressures "apparently conform to the hydrodynamic laws governing action of a current flowing normally against a submerged plane" (Eq 1).

Although Gaillard's reasoning and measurements are fairly conclusive, it is essential to keep in mind other possible mechanisms by which waves are capable of

[1] References are at the end of the paper.

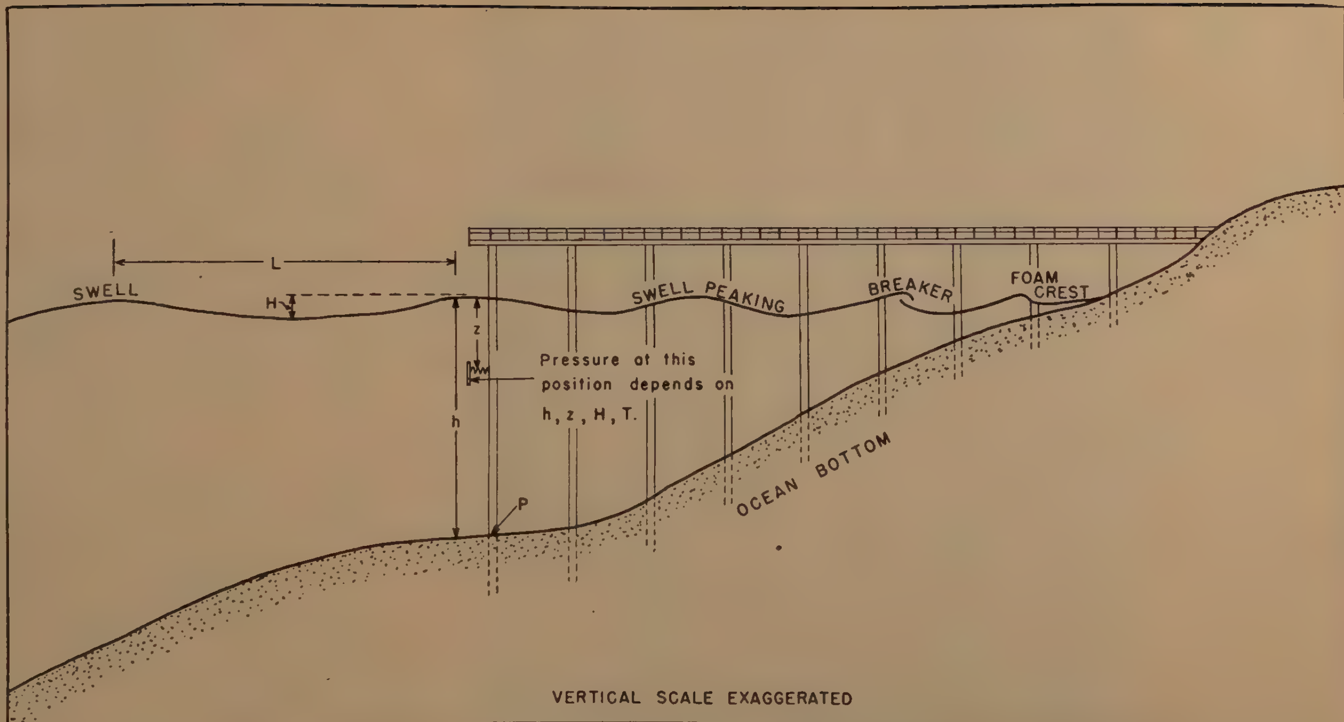

FIG 3—DETERMINATION OF ORBITAL VELOCITY.

The wave height H denotes the vertical distance between trough and crest. The wave length L is the horizontal distance between two adjacent crests. The wave period T is the time interval between the arrival of successive crests at a fixed point. The pressure exerted by waves against obstacles depends upon the depth z of the obstacle; the total depth of water, h; the wave height, H; and the wave period, T. The figure gives a schematic presentation of changes in wave characteristics that occur as waves enter shallow water.

FIG 4—WAVES IN THE STORM AREA FORM AN IRREGULAR PATTERN KNOWN AS SEA.
(Official Photograph, U. S. Navy)

FIG 5—SWELL FROM A HURRICANE.
The farther the swell travels from the storm area where it was generated, the more regular it becomes.

(Official Photograph, U. S. Navy)

exerting forces, as these might not be negligible under special circumstances. Orbital motion past the obstacle will also exert frictional drag, and this might become important in the case of very rough surfaces, such as result when barnacles attach themselves to piling. This would also increase the effective diameter D. Another possible force, similar to the drag on ships associated with the formations of wakes, is related to wave formation by the obstruction. The role of resonance characteristics of the structure has already been mentioned. Finally, in the case of breaking waves, shock loads may be caused by the impact of water masses against structures. For very rigid structures, such as breakwaters, these may be large. For wooden piles or long beams there is probably sufficient "give" to avoid large impact forces.

Under ordinary circumstances the problem then is to determine the orbital velocities, vertical or horizontal, and to compute the wave pressures according to Eq 2. Unfortunately, the determination of these orbital velocities is not simple, as it involves four factors: the height H and period T of the waves (Fig 3), the distance z beneath the surface where the velocities are to be determined, and the total depth of the water, h. The wave height and period, in turn, depend upon the character and distance of the storm that formed the waves. To give a better understanding of the principles involved, we shall review briefly the origin of waves, the manner in which they are generated, changes that occur as they travel over the open ocean, and the transformation that takes place as the waves enter shallow water.

Sea—Swell—Surf

If there were no wind, there would be no waves. Gusts of wind striking the water surface form waves which grow under the influence of the wind into a most irregular pattern known as *sea* (Fig 4). A heavy sea is raised when strong winds blow for many hours over large ocean areas. The height of the sea is determined therefore by three factors:[3]

Fetch—distance over which wind blows.

Wind speed—average speed of wind over fetch.

Wind duration—how long the wind blows.

Over land-locked areas, such as bays and small lakes, the fetch is limited by the size of the water body. In small bodies of water, very high waves cannot be formed. Over large ocean areas the fetch depends upon the size of the storm system, but is often so long that the duration becomes a limiting factor.

Waves leaving the storm areas are known as *swell* (Fig 5). Their height gradually decreases, their length increases. After having traveled thousands of miles, they become a series of long, low, and fairly regular undulations known as ground swell. They may be all but hidden by short, irregular waves newly formed at the surface.

Each ocean region has its own characteristic swell conditions reflecting the general atmospheric circulation. Along the American West Coast the swell in winter is usually the result of storms traveling south of the Aleutians into the Gulf of Alaska. During the summer the American West Coast receives swell from the storms in the "roaring forties," several thousand miles to the south of the equator. Because of the prevailing westerly winds, our East Coast does not receive long regular swell, but high surf results from occasional local storms. For similar reasons, the Gulf Coast does not receive long, regular swell, but there, exceedingly high and dangerous waves are formed by hurricanes.

As waves enter shallow water a number of striking changes take place.[4] The wave velocity and length decrease, while the height usually increases, so that the wave gradually steepens (Fig 3). As the waves

FIG 6—SURF CAUSED BY LONG REGULAR SWELL.
The crests curl and break with great intensity with all the energy going into the initial plunge.

FIG 7—SURF CAUSED BY LOCAL STORM WAVES.
The top of the wave spills over gradually and breaking continues over a long time interval.

approach the surf zone, this process of steepening accelerates suddenly—the crests rise sharply from the water surface, become peaked, and break.

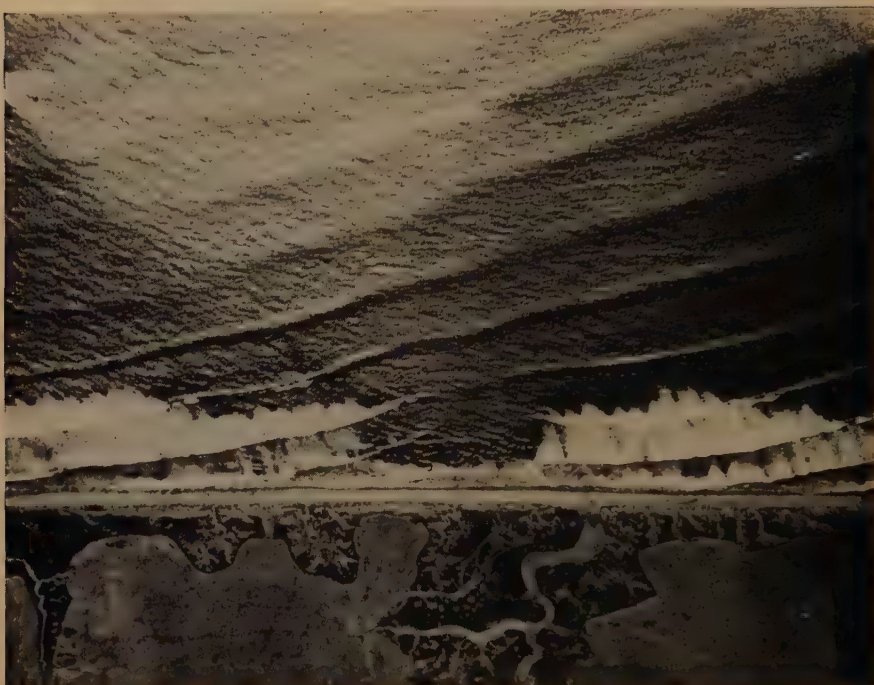

Fig 8—Long waves from the Southern Hemisphere approach the coast north of Oceanside, Calif.

The upper portion of the wave crest is in deeper water than the lower portion and therefore travels with greater velocity. As a result, the waves tend to turn parallel to shore.
(Official Photograph, U. S. Navy)

The changes just described are most noticeable for a swell from a distant storm (Fig 6). Waves formed by nearby storms, or by winds blowing directly toward the coast, have already considerable steepness out at sea, and whitecapping continues all the way to the surf zone. The top of the wave spills down the front, producing white foam and "boiling" on the leading slope, but with no real plunge of water (Fig 7). The last two figures typify two extreme types of surf: swell-surf and sea-surf.

Another important feature occurring in shallow water is the tendency of the crests to swing parallel to shore (Fig 8). This happens because the wave velocity decreases as the depth decreases, so that the portion of the crest nearer shore moves slowly while the portion of the crest in deeper water races ahead. The process is known as *wave refraction*.[5] Over a submarine canyon the central portion of the crest is in deeper water and moves faster than the portion on either side (Fig 9). Consequently the waves fan out, resulting in divergence (low waves) over the head of the canyon and convergence (high waves) on either side. Piers and structures are often built opposite the heads of submarine canyons to take advantage of this feature (Fig 10). Underwater ridges near shore have an effect opposite to that of canyons (Fig 11). Waves passing over the ridge are in shallower water and are therefore retarded, and on

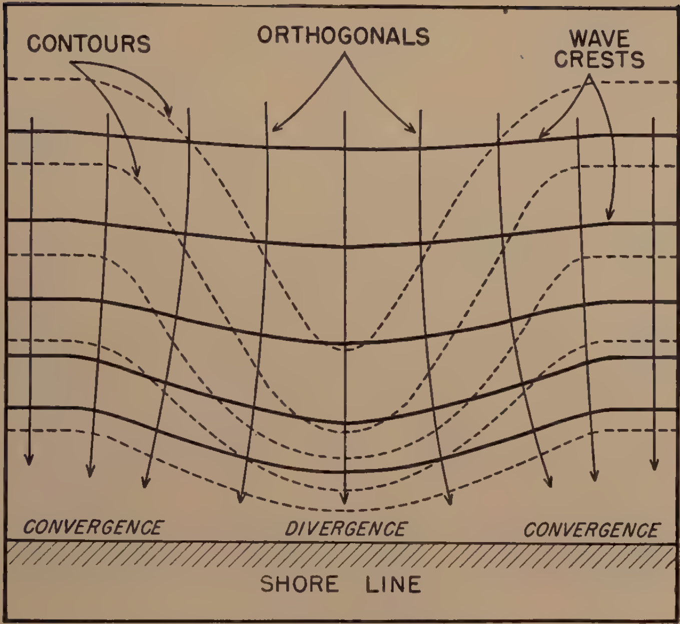

FIG 9—REFRACTION OF WAVES BY A SUBMARINE CANYON.
Waves move faster over the canyon than on either side of the canyon, resulting in divergence (low waves) over the mouth of the canyon and convergence (high waves) on either side.

FIG 10—WAVE REFRACTION AT MOSS LANDING.
Note the flat water at the end of the pier where the Monterey Canyon approaches the shore. (Photograph by Department of Engineering, University of California)

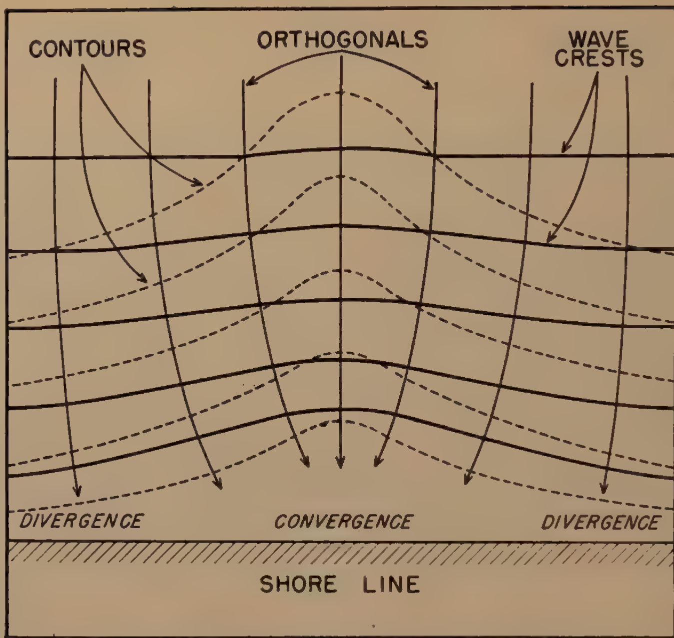

FIG 11—REFRACTION OF WAVES BY A SUBMARINE RIDGE.
Directly over the ridge waves lag behind, and on either side waves move ahead, creating a convergence (high waves) over the ridge.

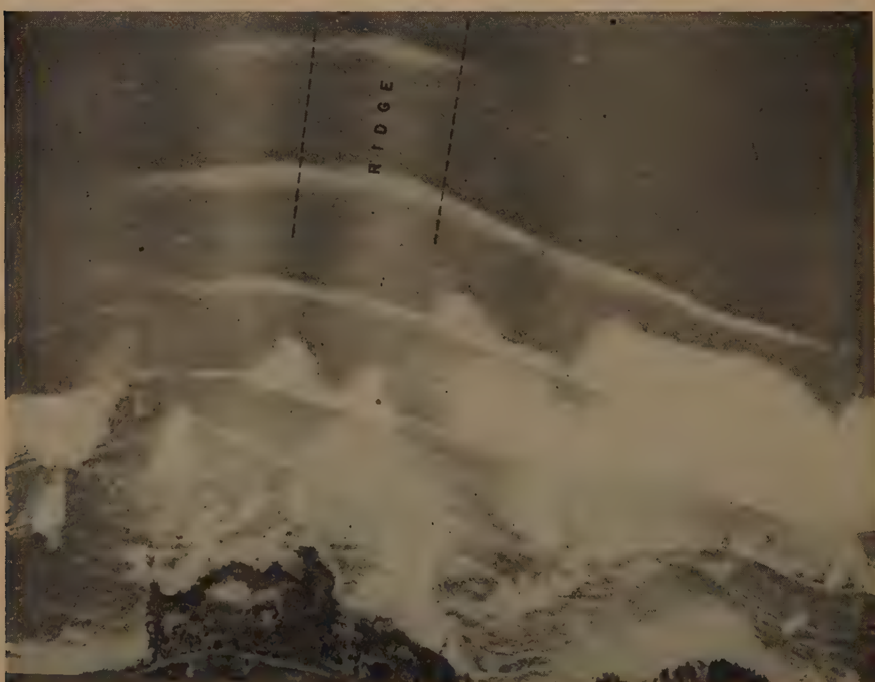

FIG 12—REFRACTION OF WAVES OVER RIDGE ALONG THE NORTHERN SHORE OF OAHU, T. H.
Over the ridge, waves lag behind and are higher than on either side.
(Official photograph, United States Army)

either side waves move ahead creating a convergence over the ridge (Fig 12).

The selection of sites for the building of piers and other structures should be made with these factors in mind. *In some regions a slight change in location might mean a reduction of wave action by over 50 pct.*

Computation of Wave Characteristics

In order to estimate wave action on structures it is first necessary to know the dimensions of the waves at the chosen locality. Depending upon the problem on hand one may be interested in the mean annual wave conditions, the mean seasonal wave conditions, the worst possible conditions, or conditions likely to be encountered for the next two days. For all but the last case it would seem reasonable to make use of past wave observations, but unfortunately very few observations are available which are adequate either with regard to quantity or quality. If we had to rely upon direct observations only, this discussion would be chiefly of academic interest.

In the preceding section the effects of storm conditions and bottom topography upon wave characteristics have been discussed. The relationships governing these effects have been determined, and it is possible to *forecast* waves with considerable accuracy, provided adequate weather maps and bottom charts are available. The method for forecasting waves was developed during the war in order to assist in the planning and operation of amphibious landings.[3,4,6,7,10] The method can be used in two ways: It can be used to forecast waves for a fixed time and day on the basis of current weather maps (usually it is not possible to make a reliable forecast for more than two days in advance); it can be used also to compute average and extreme wave conditions on the basis of historical weather maps, which are now available for the northern hemisphere for the past 18 years. In this manner statistical information regarding the distribution of wave heights and periods at a fixed locality and depth has been obtained without resorting to costly and prolonged observations.

Orbital Motion

Returning to the discussion of orbital motion, it is necessary to give a precise definition of what is meant by deep and shallow water. Shallow water is water of depth (in feet) less than $2T^2$, where T is the wave period in seconds. In deep water, that is in water of depth exceeding $2T^2$, the bottom exerts no appreciable effect on the wave characteristics.

Fig 13 gives schematic representations of orbital motion of progressive waves in deep water, shallow water, and at the breaking point. The arrows in the upper left figure represent direction and speed of orbital motion in *deep water* at a given *instant.* Directly beneath the crest the water moves horizontally and with the wave; beneath the trough the water moves horizontally but in a direction opposite to that of the waves. Ahead of the crest the water is rising, behind the crest it is falling. The dashed curves represent streamlines, i.e., lines that are everywhere parallel to the direction of orbital motion.

The upper right figure shows the movements of *fixed water particles* during the passage of a wave, that is the particle trajectories, again in *deep water.* Each water particle describes a circle. To the extreme right of the figure, where the trough of the wave is located, the water particle occupies its lowest position. As the crest approaches, the particle moves clockwise and reaches its highest point at the instant the crest passes. After the crest has passed, the particle starts moving downward and reaches its lowest position with the arrival of the subsequent trough.

The two upper figures represent therefore the same phenomenon from two points of view. From either figure it can be seen that the maximum horizontal and vertical velocities are equal. The maximum horizontal

and vertical loads, which are alternately exerted by the waves on a fixed beam with its axis vertical to the plane of the figure, must therefore also be equal. The maximum

The central figures in Fig 13 show the streamlines and trajectories for wave motion in *shallow water*. Because of the restrictive effect of the sea bottom upon the

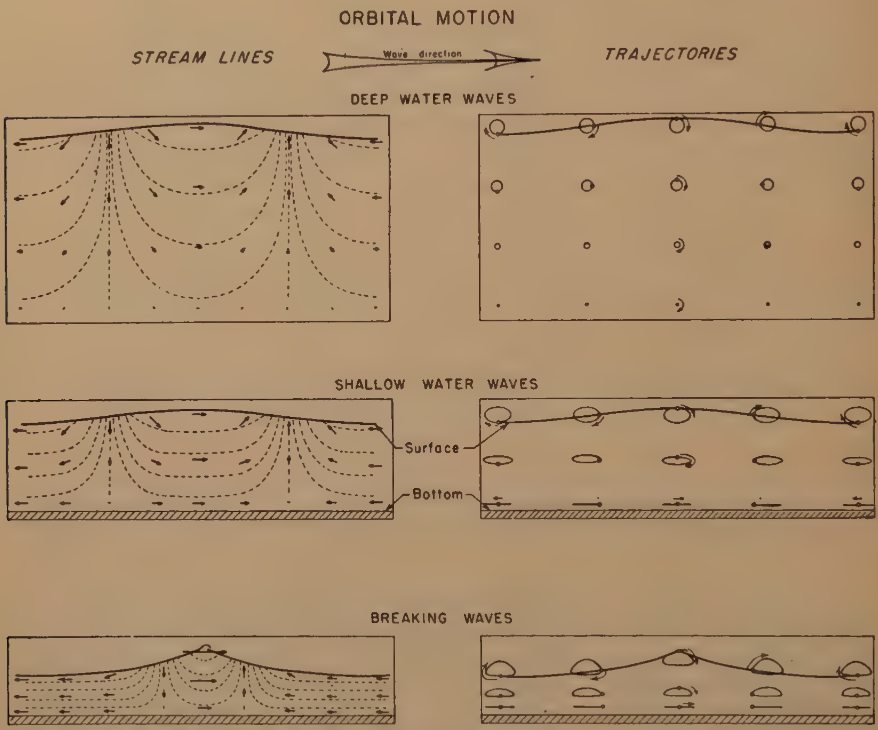

FIG 13—ORBITAL MOTION IN PROGRESSIVE SURFACE WAVES.

The dashed lines in the figures to the left are the streamlines, i.e., lines everywhere parallel to the flow. The direction and length of the arrows indicate direction and velocity of orbital motion. The figures to the right show the particle trajectories, i.e., the paths described by fixed particles of water. For further description, see text.

horizontal forces occur as the crest or trough passes, being directed with or against the direction of wave motion respectively; the maximum vertical forces occur midway between the passage of crest and trough, being directed upward ahead of the crest, downward behind the crest.

The orbital velocities are the largest at the surface and they decrease rapidly with depth. At a depth corresponding to $2T^2$ the velocities are negligible. This applies equally to the horizontal and vertical velocity components.

water movements, the circular motion that existed in deep water is squeezed into elliptical motion and at the very bottom is distorted into linear back and forth movement. The motion is no longer symmetrical because the horizontal velocities exceed the vertical velocities. Otherwise, the orbital motion is similar to that in deep water, directed horizontally and with the waves directly under the crest, against the waves under the trough, upward or downward between crest and trough. The vertical movement ceases altogether at the bottom

where the orbital motion consists entirely of back and forth movement of the water. A fixed beam in shallow water is subjected to larger horizontal forces than vertical forces. This is increasingly true the shallower the water and, for any fixed depth, the deeper the position of the beam beneath the water surface. The motion retains a certain degree of symmetry insofar as the maximum upward forces equal the maximum downward forces, and the maximum forces to the right equal the forces to the left.

For the case of breaking waves, as represented by the bottom two figures (Fig 13), even this symmetry does not hold. Practically all the forward motion is confined to the narrow region near the crest. Between crests we find long flat troughs during which the water moves relatively slowly opposite to the wave direction. To quote a numerical example, in the case of an 8-sec wave, the shoreward movement of the water will take place in 2 sec, the seaward movement in 6 sec. Directly at the crest of the breaking waves the water moves shoreward with the velocity equal to that of the wave itself. This feature may indeed be regarded as an explanation of why waves break. The orbital velocity beneath the crest decreases very rapidly downward, and equals only one-half the surface value at the level corresponding to the undisturbed sea surface, and one-third the surface value near the sea bottom. The vertical velocities are even smaller compared to the horizontal velocities than they were in the case of shallow water.

A fixed beam would therefore be subjected to the maximum possible pressure if it were located at the top of the breaking crest. But no matter where it is located, by far the largest forces will be directed horizontally, in the direction of wave motion, and will occur at the time when the wave is breaking over the beam. For most engineering problems a calculation of the maximum forces is probably sufficient.

Theory

So far, the discussion of orbital motion has been purely qualitative. For deep and shallow water, all features which have been described are contained quantitatively in the equations:

$$u = U \cos\left(\frac{2\pi x}{L} - \frac{2\pi t}{T}\right), \quad U = \frac{\pi H}{T}\,\frac{\cosh 2\pi(z+h)/L}{\sinh 2\pi h/L} \qquad [4a, b]$$

$$w = W \sin\left(\frac{2\pi x}{L} - \frac{2\pi t}{T}\right), \quad W = \frac{\pi H}{T}\,\frac{\sinh 2\pi(z+h)/L}{\sinh 2\pi h/L} \qquad [5a, b]$$

which were derived theoretically by Airy in 1845. In these equations u and w are the horizontal and vertical components of the *instantaneous* orbital velocities, which change periodically with distance x and time t; U and W are the corresponding *maximum* values of orbital velocity expressed as functions of the wave height H; wave period T; wave length L; distance beneath the surface z; and depth of water h. The symbols *sinh* and *cosh* denote hyperbolic functions. These equations are complicated, but they can be presented in graphical form[8] and with some experience they are not difficult to handle. Objections have been raised against these equations because of assumptions and simplifications in their derivation. For that reason there has been a tendency to discount their practical use. Recently, especially during the war, the Airy wave equations have been checked in a large number of ways and found remarkably accurate (Fig 14). It may be said that for most practical problems the values obtained from Eq 4 and 5 are more accurate than could be determined by direct measurements with all but the most refined instruments. The usefulness of the Airy theory is born out by many successful applications; among them prob-

lems involving the forecasting of waves in shallow water, underwater depth determination, and the movement of submerged mines.

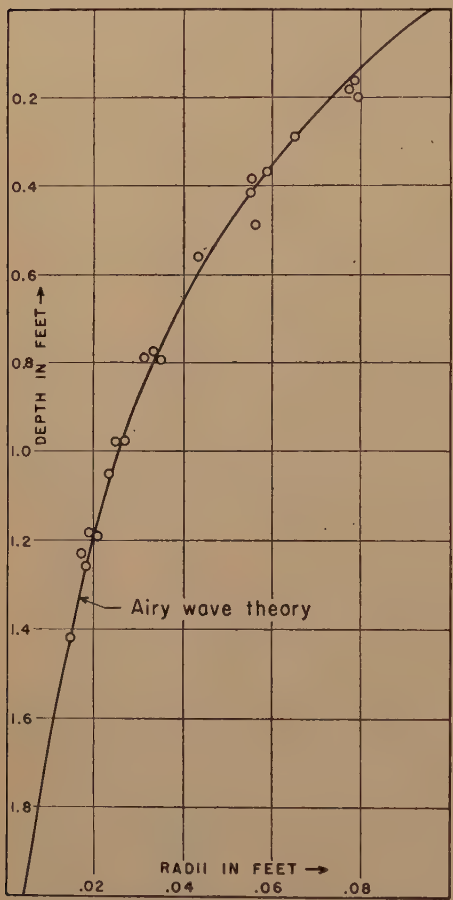

FIG 14—COMPARISON BETWEEN THEORETICAL AND OBSERVED VALUES OF ORBITAL RADII. (From Beach Erosion Board.[9])

The maximum horizontal pressures, P_h, are found by substituting Eq 4*b* into Eq 2:

$$P_h = C_D U^2 \qquad [6]$$

Similarly the vertical forces are given by the equation

$$P_v = C_D W^2 \qquad [7]$$

where the drag coefficient C_D now depends upon the shape and effective surface area of the obstacle relative to vertical flow. The net maximum forces at any instant are given by

$$P = C_D(U^2 + W^2) \qquad [8]$$

provided C_D is independent of the direction of flow.

The maximum horizontal forces from surface to bottom on a vertical beam or pile of constant diameter D are found by integration, using Eq 6 and 4*b*:

$$F = \int_{-h}^{0} P_h dz = C_D D H^2 \frac{\pi L}{4T^2} (\coth \alpha + \alpha \sinh^{-2} \alpha) \qquad [9]$$

where $\alpha = 2\pi h/L$. The moments about the point where the pile is driven into the bottom (P in Fig 3) equal:

$$M = \int_{-h}^{0} P_h z dz = C_D D H^2 \frac{L}{16T^2} \cdot (2\alpha \coth \alpha + \alpha^2 \sinh^{-2} \alpha - 1) \qquad [10]$$

But according to Airy's theory[10]

$$L = \frac{gT^2}{2\pi} \tanh \alpha \qquad [11]$$

which, when substituted into Eq 9 and 10 gives:

$$F = C_D D H^2 K_F, \quad K_F = \frac{g}{8}\left[1 + \frac{2\alpha}{\sinh 2\alpha}\right] \qquad [12]$$

$$M = C_D D H^2 h K_M, \quad K_M = \frac{g}{8}\left[1 + \frac{\alpha}{\sinh 2\alpha} - \frac{\tanh \alpha}{2\alpha}\right] \qquad [13]$$

The functions K_F and K_M, which are plotted in Fig 15 as a function of h/T^2, vary between relatively narrow limits, and may be considered nearly constant. The forces and moments vary approximately as the square of the wave height. The forces depend only slightly upon the depth of

water, whereas the moments are roughly proportional to the depth.

Much less is known about breaking waves, with regard to both theory and observation. Some success has been achieved by the application of the so-called "solitary wave theory." According to this, the equations for forces and moments are more complicated than those derived from the Airy wave theory. It is hoped that they can be discussed at a later time, after the theory has been compared to observations.

For the special case of the forces exerted at the very crests of breaking waves, the orbital velocity equals the wave velocity, and is given by the equation

$$V_b^2 = g(h_b + H_b) \qquad [14]$$

where h_b is the depth of water at the breaking point, H_b the height of the breaking waves. Taking

$$h_b/H_b = 1.28 \quad \text{and} \quad h_b/H_b = 1.72 \qquad [15a, b]$$

for swell-surf and sea-surf respectively, and substituting these ratios into Eq 2 and 11, the result is

$$P_b = 73C_DH_b \quad \text{and} \quad P_b = 87C_DH_b \qquad [16a, b]$$

for the two extreme cases of long swell and short storm waves.

These formulas can be checked by means of measurements by Gaillard[2] with a dynamometer ($C_D = 1.31$). Observations at St. Augustine, Fla., refer to swell-surf and agree remarkably well with Eq 16*a* (see Fig 16). Observations at Lake Superior refer to sea-surf and agree on the average with Eq 16*b*. Eq 16*a*, *b* permit a rapid estimate of the dynamic pressure exerted at the tops of breaking waves. These

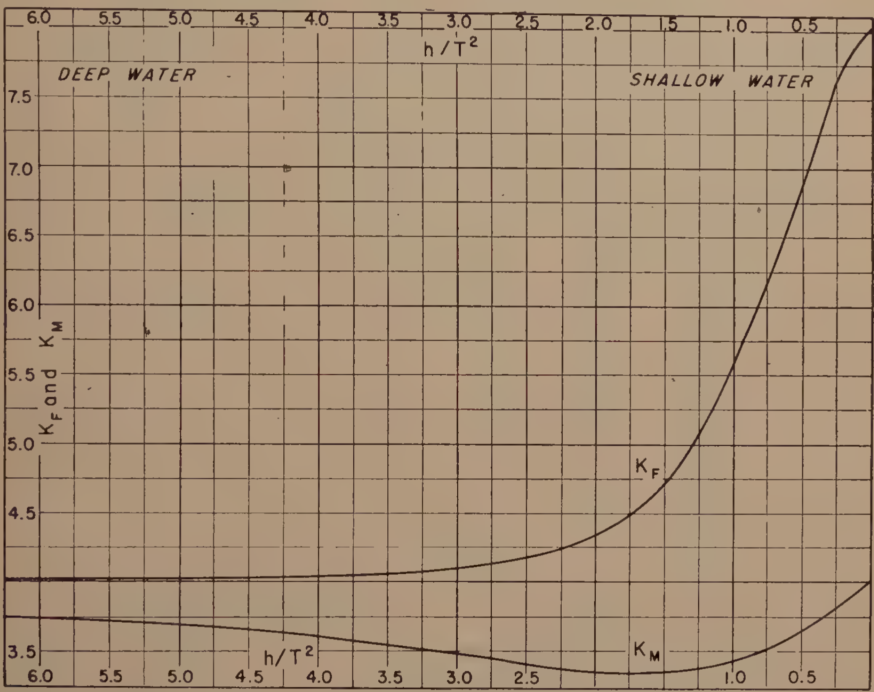

FIG 15—CORRECTION FACTORS FOR THE COMPUTATION OF HORIZONTAL FORCES AND MOMENTS AGAINST PIER PILES.
For description, see text.

dynamic pressures represent the worst possible pressures to which structures may be subjected by wave action.

water, had periods of 9 sec, and approached from the west-northwest. The surf had the characteristics of swell-surf (Fig 6).

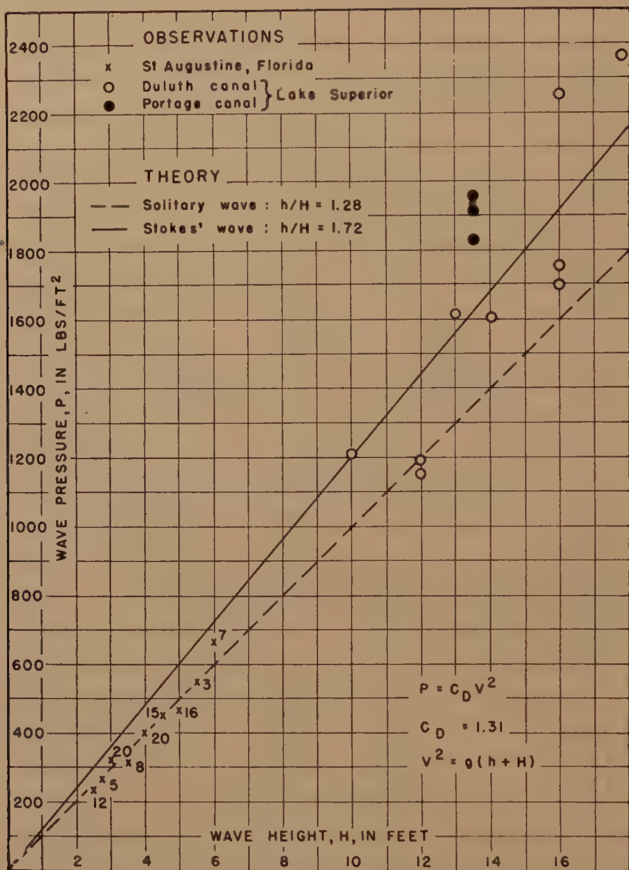

Fig 16—Comparison between theoretical and observed values of the pressure exerted at the crest of breaking waves.

Example

The principles discussed so far can best be summarized by an actual example. Suppose it is desired to find the maximum forces and moments exerted by wave action against vertical cylindrical piles of 3-ft diam, located off the Scripps Institution, La Jolla, Calif. Applying the methods of wave computation,[7] using Northern Hemisphere weather maps for the years 1936, 1937 and 1938, it was found that the maximum waves were 20 ft high in deep

The wave characteristics were computed for selected depths, starting at a depth of $2T^2 \approx 160$ ft where they enter shallow water. The second line in Table 2 gives the height of these waves at various depths, taking also into account the effect of refraction.[10] The asterisks in the last two columns mean that the waves have broken, and that calculations are based on the solitary wave theory.

The third line in Table 2 gives the elevation of the highest point of the crest

above the mean water surface. Prior to breaking, the highest point is one-half of the total wave height above the mean water level. At and after breaking the highest crest point lies ¾ of the wave height above the mean water level.

The Table next gives the values of maximum horizontal orbital velocities, U, pressure is roughly 10 lb per sq ft, compared to a maximum wave pressure of 363 lb per sq ft! Yet according to a "practical" engineering rule, wave loads equal wind loads plus 30 pct!

The last two lines in Table 2 give maximum forces, respectively moments, according to Eq 12 and 13.

TABLE 2—*Calculation of Wave Characteristics, Forces and Moments against Vertical Piles off Scripps Institution Pier*

(Diameter of Piles: $D = 3$ ft
$C_D = 0.33$)

(Deep water wave height: 20 ft
wave period: 9 sec)

Depth of water, ft		160	100	40	20	10
Wave height, ft		20	14	12	15*	8*
Crest elevation above M.S.L.		10	7	6	12	6
Maximum Horizontal Orbital Velocities, ft per sec.	At crest	7	6	6	33	24
	Depth beneath M.S.L., ft: 0	7	5	5	14	10
	10	6	5	5	12	8
	20	5	4	4	11	
	40	4	3	4		
	100	2	2			
	160	1				
Dynamic Pressure against Pile, lb per sq ft.	At crest	16	12	12	363	192
	Depth beneath M.S.L., ft: 0	16	8	8	65	33
	10	12	8	8	48	21
	20	8	5	5	40	
	40	5	3	5		
	100	1.3	1.3			
	160	0.3				
Total horizontal forces against pile, lb		1,740	1,000	1,000	9,300	2,400
Total moments against pile, lb-ft		214,000	66,000	21,000	216,000	27,000

* Waves have broken and solitary wave theory applies.

which occur at the instant the wave crest passes the pile. These were computed according to Eq 4*b* and the solitary wave theory. The velocities decrease from the surface downward. They are by far the largest at the initial point of breaking, that is, at a depth of 20 ft.

The next section of Table 2 gives the wave pressures against the pier piles at various distances beneath the water surface, computed according to Eq 6 and using $C_D = 0.33$ (see Table 1). It is of interest to compare these with the pressure that a 100-knot wind would exert on the same piles. Taking the kinematic viscosity of air as 1.5×10^{-4}, one obtains the Reynolds' number 1.1×10^{6}, hence $C_D = 0.33$. The

The stated depth refers to the time average of the depth at a given locality. In a heavy storm when the water is piled against shore, the average depth of water at a given locality would be larger than the average depth at the same locality before the storm. This rise in the mean water level (storm tide) may be of the order of 10 ft in very shallow water (0 to 20 ft), of the order of 5 ft in water of intermediate depth (30 to 40 ft), and negligible in deeper water.

Summary and Conclusions

The forces exerted by waves against structures are the result of a long chain of

events, starting with the formation of a storm over the ocean, and followed by the generation of waves in the storm area (sea), the travel of these waves from the storm area (swell), and the transformation of the waves upon entering shallow water until they break (surf). Because of the active interest in meteorology many more data are available concerning the nature of the storms, than concerning any of the subsequent events.

Since the relationships between the various links of this chain are fairly well established, it is possible to forecast wave conditions from synoptic weather maps, or to compute past wave conditions from historical weather maps. In this manner one can obtain rational estimates of the wave conditions at a given locality.

From a knowledge of the wave height and period one can compute the water (orbital) motion, and then apply a well-known engineering formula to obtain dynamic pressures. The calculation is based on a hundred-year old theory which has received too little attention in engineering praxis.

Although there exists an urgent need for obtaining additional data on wave forces, either by measurements in the field or by model studies, the theory can serve a useful purpose as a guide in such measurements, and as a means of making preliminary estimates of the forces and moments to be expected.

Acknowledgment

It is a pleasure to acknowledge my indebtedness to Mercer H. Parks, of the Humble Oil Company, for having aroused my interest in the problems discussed here, and for having examined this paper.

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Engineering Characteristics of the Gulf Coast Continental Shelf

By M. B. Willey*

(Tulsa Meeting, October 1947)

Abstract

The Louisiana Continental Shelf is a submarine area extending offshore as much as one hundred miles. The Gulf bottom in this region varies considerably in extent, profile and composition and consists largely of sedimentary deposits, predominantly those of the Mississippi River. It is very young in a geological sense.

Up to the present time few major structures have been erected offshore in the Gulf and no comprehensive preliminary tests have been carried out. Results of pile-driving tests are of little value as actual bearing capacities far exceed the dynamic resistance to driving as measured by conventional formulas. Soils encountered are, with few exceptions, cohesive and piling consequently develop their supporting power through surface friction.

Because of the time required and relatively high costs, no complete load tests have been made. The results of those tests which have been made, and information obtained from pulling piling in one structure, indicate that design loadings could be considerably increased, and it is contended that comprehensive preliminary investigations including an actual load test, combined with borings and examination of materials encountered by competent soil experts, would effect economies in design far in excess of their cost.

The Louisiana Continental Shelf—General

The Louisiana

. . . continental shelf is a submarine area which extends seaward for as great a distance as one hundred miles off the present shoreline. The Gulf bottom in this region is characterized by low slopes and its outer margin is outlined by the fifty fathom (300 ft.) contour. South of the margin of the shelf the slopes steepen abruptly in the continental slope zone and plunge into the deeps of the Gulf of Mexico.[1]

The engineer who is called upon to design a structure on this shelf is concerned only with the uppermost portion to a depth generally not to exceed 100 to 150 ft. This layer is very young in a geological sense, and it has the characteristics usually associated with infancy. A few of these are lack of strength, lack of uniformity, and high water content. It consists of the sedimentary deposits of the various rivers and streams entering the Gulf. These streams are all heavily burdened in quantities sufficient to fill the areas at their mouths, were it not for the fact that continual subsidence, equal or greater in amount and acting directly opposite, prevail over the sedimentary workings of the streams. This subsidence has been estimated by geologists to be at the rate of at least one foot per century.

Influence of Mississippi River

The Mississippi River, which has been the predominant factor in the formation of practically all the Louisiana continental shelf, is one of two rivers flowing into the Gulf that have been able to build protruding deltas. The Mississippi has done so because of its enormous size and load. It deposits sediments in amounts sufficient to replace and actually gain on the amount of subsidence.

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[1] References are at the end of the paper.

The Mississippi at the present time is yearly carrying to the Gulf enough mud and sand to cover an area a mile square to a depth of two hundred sixty eight feet. In the 30,000 years since the glaciers started their slow retreat from the North American Continent, the Mississippi has brought to South Louisiana enough sediment to bury the entire state (48,000 sq. miles in area) to a depth of one hundred eighty eight feet. It is obvious to anyone that this sediment has been spread out 'not over the entire state' but over the delta and coastal parishes and over a portion of the shallow water just off shore. Concentrated in this local area, this sediment has caused a corresponding sinking.[2]

These sediments of the Mississippi (augmented, to a small extent by the other small rivers and streams) are the materials of the continental shelf along the entire coast of Louisiana. This huge mass of stream deposits is known as the Recent alluvium and "consists of a sequence of sediments which grades irregularly upward from coarse, graveliferous sands into progressively finer deposits of sands, silts, and clays."[1] It overlies the Pleistocene (See Fig 1) in depths varying along the coast line, from a few feet at the western edge of Louisiana, to as much as 350 ft and more in the area south of Houma and New Orleans. The upper or non-graveliferous section of this Recent alluvium consists of sands, silts, and clays having a maximum known thickness of over 250 ft near the Gulf shore south of Houma. The outcropping of the Pleistocene can be taken to be at or near the interior edges of the coastal swamps. In western Louisiana the Pleistocene dips south at the rate of about one foot per mile and borings of the U. S. Engineers have located it at a depth of about 17 ft below mean sea level (see Table 1) near Grand Chenier in Cameron Parish, La. The rate of dip increases gradually eastward until the vicinity of Marsh Island is reached. Here borings have encountered it at a depth of about 40 ft below m.s.l. Continuing eastward this depth increases very rapidly due to dipping not only south into the Gulf but also east into the trench of the Mississippi. The area along the remainder of the coast is made up of the numerous deltas of the Mississippi River drainage system, throughout which the Recent alluvium is extremely thick.

TABLE 1—*Borings*[a]

B-1[b]

Water 4 Ft Deep (Mean Low Gulf)

Elevation, Ft M. L. G.	Moisture, Dry Weight, Pct	Consistency	Classification
−5			Gray shells
−9	60.8	Soft	Gray silty clay
−14	59.7	Medium	Gray silty clay—tr. humus
−19	43.7	Medium	Gray clay silt
−24	43.7	Medium	Gray clay silt
−29	47.1	Firm	Gray silty clay
−34	67.2	Firm	Gray medium clay

B-2[b]

(Water 7 Ft Deep (Mean Low Gulf)

Elevation, Ft M. L. G.	Moisture, Dry Weight, Pct	Consistency	Classification
−8	400.0	Very soft	Gray clay—40 pct humus tr. shells
−12	584.9	Medium	Dark brown humus—clay
−17	363.0	Medium	Dark brown humus—clay
−22	95.3	Soft	Gray med. clay, shells; tr. humus
−27	46.2	Medium	Gray silty clay
−32	68.4	Medium	Gray medium clay
−37	26.6	Stiff	Gray silty clay
−42	23.2	Very stiff	Brown medium clay (pleistocene)

B-3

In the drilling of Superior Oil Company's Gulf of Mexico—State 1-A (T-1 on Fig 2) only silt and clays of various consistencies were encountered to a depth of over 1000 ft.

[a] For location of borings see Fig 2.
[b] Information—Borings B-1 and B-2: H. A. Huesmann, Chief of Soil Section, U. S. Engineers Office, New Orleans Dist., New Orleans, La.

Composition

If we glance at the maps of the U. S. Coast and Geodetic Survey covering the continental shelf south of Louisiana we will find that they chart many varied classifications of material as comprising the Gulf floor, including mud, sands, and clays of various consistencies, together with local deposits and reefs of shell. These descriptions apply, of course, only to the

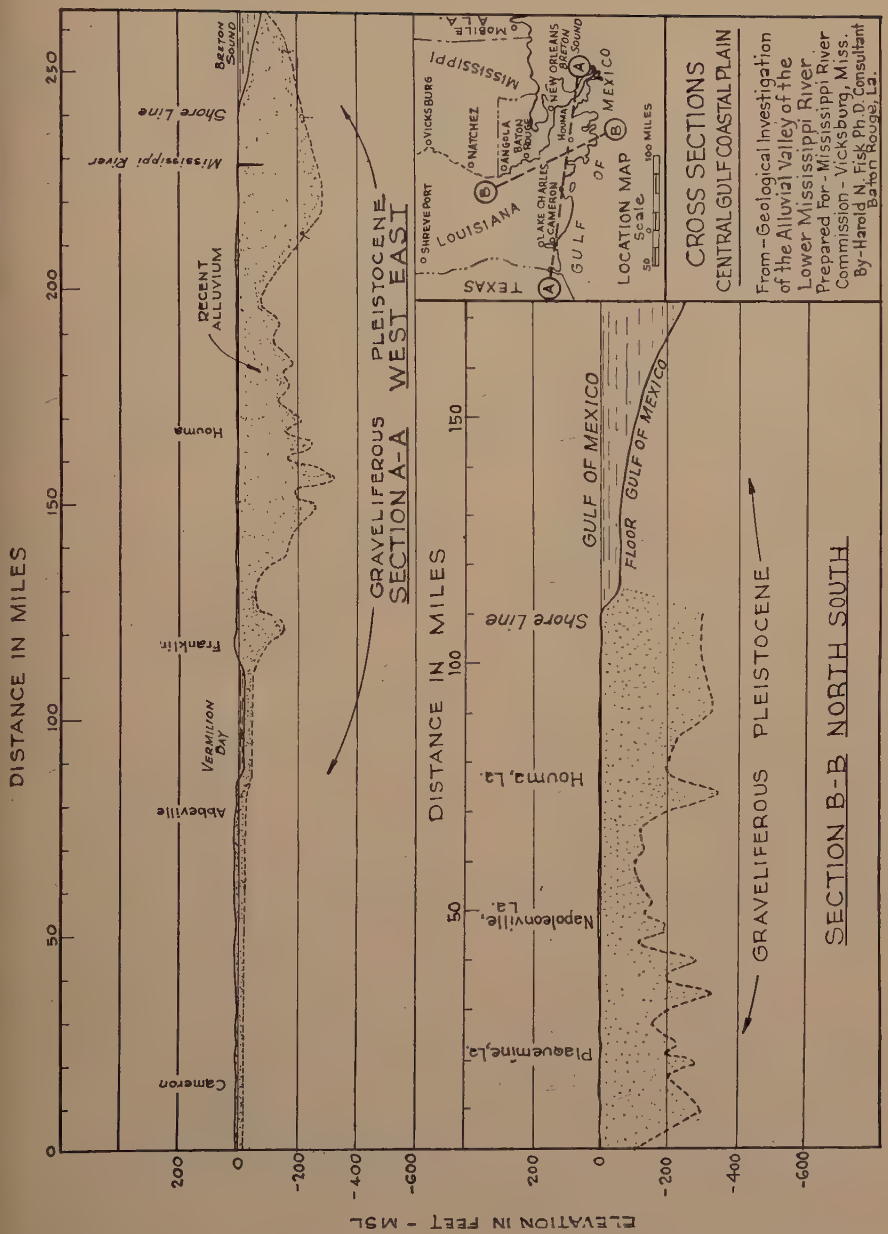

FIG 1—CROSS SECTIONS OF CENTRAL GULF COASTAL PLAIN.

surface. Unfortunately, there has been very little data obtained with regard to the nature of the material immediately below the surface. As yet no investigations, made preliminary to the installation of offshore structures, have included the taking of comprehensive borings; the few wells which have been drilled have not sampled or classified the surface formations and geophysical crews, who have bored only to shallow depths, have not been interested in the materials encountered.

In this country the standard classification of materials, as found in sedimentary deposits, is that of the Bureau of Soils of the U. S. Department of Agriculture. It is as follows:

Name	Size of Particles, Millimeter
Colloids	Less than 0.001
Clay	0.001 to 0.005
Silt	0.005 to 0.05
Very fine sand	0.05 to 0.1
Fine sand	0.1 to 0.25
Medium sand	0.25 to 0.5
Coarse sand	0.5 to 1.0
Fine gravel	1.0 to 2.0

We may rest assured that most structures erected on the continental shelf adjacent to the coast of Louisiana must depend for support on such materials, with an occasional intermingling of a layer or deposit of humus or shell. In general, but not always, they will be more consolidated at the deeper depths and the water content will be lower.

Pile Bearing Tests

Up to the present time, the only structures erected offshore in the Gulf of Mexico have been those required for the drilling of exploratory oil wells and in all cases these have used piles to support the elevated platforms. As would be expected, the results of the driving of test piling in these various locations show considerable variation. (See Fig 2 and Tables 2 to 9 inclusive). All are in the area in which the Recent alluvium is thick and it is certain that in none of them have piling reached the Pleistocene. The resistance supporting these piles is due to the friction of the earth against the side of pile, with little or no assistance from actual bearing at the point. Fortunately, the silts, clays, and sands of these sedimentary deposits have a fairly high shearing value and, what is even more fortunate, they possess the ability to set or freeze around the pile after it has remained in place for a period of time.

Table 2—*Pile Test—T-1*[a]

Company: Superior Oil Company.

Location: See Fig 2; water, 22 ft deep; Gulf Floor, 0.0.

Pile: 7-in. od steel pipe, 112 ft long, 24#/lin ft T. and C. and welded.

Hammer: No. 1 Vulcan steam; total weight, 10,200 lb; ram, 5,000 lb; stroke 36 in.

Depth of Penetration, Ft	Increment, In.	Blows	Penetration per Blow, In.	Safe Load in Tons, E. N. Formula[b]
22.0	264	Pile hammer dropped free—15 ft		
53.0	372	Hammer free on pile		
56.0	36	3	12.0	1.24
58.0	24	5	4.8	3.06
62.0	48	16	3.0	4.84
66.0	48	20	2.4	6.00
68.0	24	13	1.84	7.75
70.0	24	14	1.71	8.30
76.0	72	48	1.5	9.37
78.0	24	15	1.6	8.85
80.0	24	13	1.85	7.71

Contact area of pile: $\frac{7}{12} \times 3.1416 \times 80 = 147$ sq ft.
Safe Load per sq ft contact area:
(E. N. Formula) $15{,}420 \div 147 = 105$ lb.
Pile permitted to set 15 hr before driving resumed.

Depth of Penetration, Ft	Increment, In.	Blows	Penetration per Blow, In.	Safe Load in Tons, E. N. Formula[b]
80.6	7	10	0.70	18.75
81.9	16	20	0.80	16.70
83.6	20	20	1.00	13.63
Total	43	50	0.86	15.65

Contact area of pile:
$\frac{7}{12} \times 3.1416 \times 83.6 = 153$ sq ft.
Safe load per sq ft contact area:
(E. N. Formula)—$31{,}300 \div 153 = 204$ lb.

[a] Information by: W. S. Law, Superintendent, Superior Oil Co., Lafayette, La.
[b] Engineering News formula.

In Table 9 the results of the driving of seven test piling, in the area presently active off the Louisiana Coast, have been summarized. These tests included one creosoted fir and six steel piling of various diameters. By converting to a unit of safe load per square foot of contact area a fair

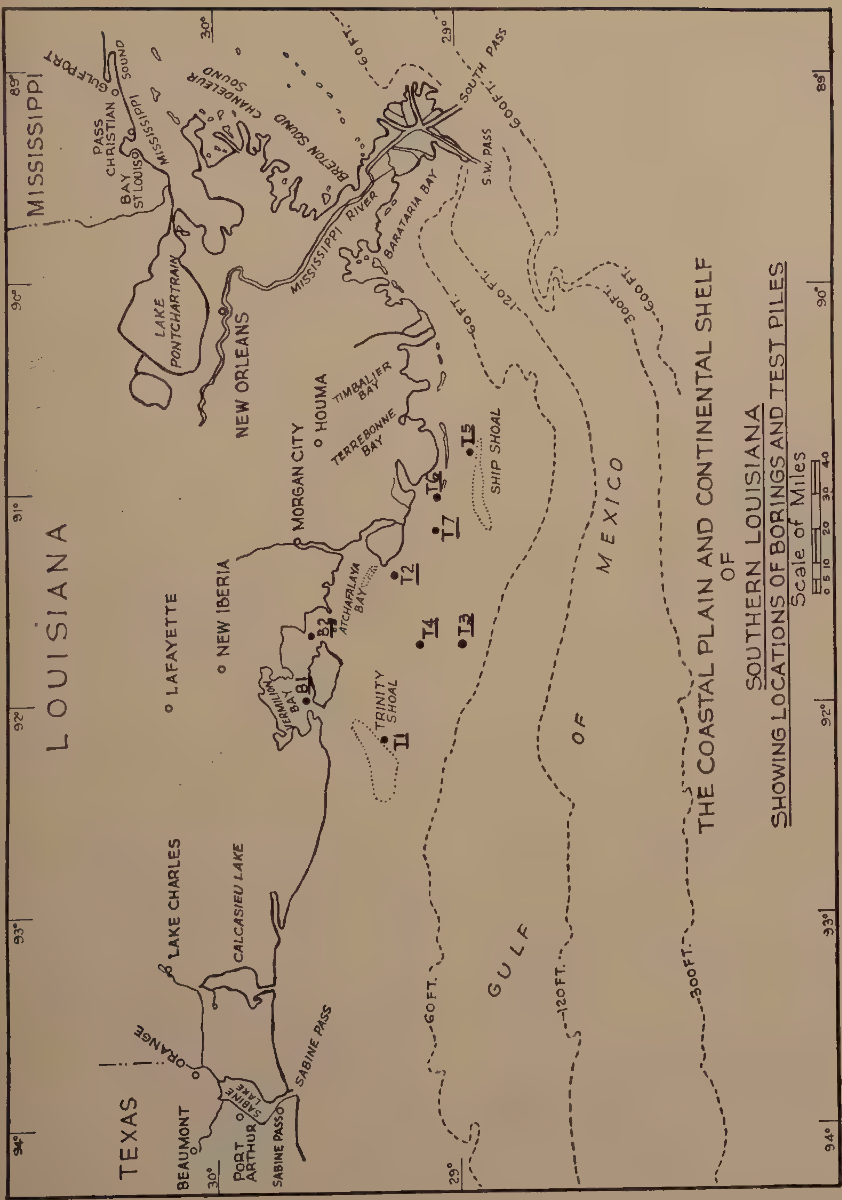

FIG 2—COASTAL PLAIN AND CONTINENTAL SHELF OF SOUTHERN LOUISIANA.

TABLE 3—*Pile Test—T-2*[a]

Company: Magnolia Petroleum Company.
Location: See Fig 2; water, 16 ft deep; Gulf Floor, 0.0.
Pile: 15-in. od steel pipe, 1 in. wall, 120 ft 6 in. long, 149.5#/lin. ft; welded joints; total weight, 18,000 lb.
Hammer: No. 1 Vulcan steam; total weight, 10,200 lb; ram 5,000 lb; stroke, 36 in.

Depth of Penetration, Ft	Increment, In.	Blows	Penetration per Blow, In.	Safe Load, Tons, E. N. Formula[b]	Safe Load, Tons, Mod. E. N. Formula[c]
24.0		Weight of Pile only			
60.0		Hammer free on pile			
62.9	34.8	10	3.48	4.2	3.9
65.2	27.6	11	2.51	5.7	5.2
67.0	21.6	13	1.66	8.5	7.4
68.4	16.8	8	2.10	6.8	6.1
70.3	22.8	11	2.07	6.9	6.2
74.7	52.8	32	1.65	8.6	7.5
80.6	70.8	51	1.39	10.1	8.6
85.0	52.8	42	1.26	11.0	9.3
86.7	20.4	21	0.97	14.0	11.3
88.8	25.2	22	1.15	12.0	10.0
90.6	21.6	20	1.08	12.7	10.4
92.3	20.4	20	1.02	13.4	10.9
93.9	19.2	20	0.96	14.1	11.4
95.8	22.8	23	0.99	13.8	11.1
97.0	14.4	20	0.72	18.3	13.9

Contact area of pile:
$\frac{15}{12} \times 3.1416 \times 97.0 = 380$ sq ft.
Safe load per sq ft contact area:
(E. N. Formula)[b]—36,600 ÷ 380 = 96 lb.
(Mod. E. N. Formula)[c]—27,800 ÷ 380 = 73 lb.
Pile permitted to set 24 hr before driving resumed:

97.08	1.0	9	0.11	71.4	31.9
97.63	6.5	20	0.33	34.9	21.7
98.75	13.5	50	0.27	40.5	23.8
Total	21.0	79	0.266	41.0	24.0

Contact area of pile:
$\frac{15}{12} \times 3.1416 \times 98.75 = 388$ sq ft.
Safe load per sq ft contact area:
(E. N. Formula)[b]—82,000 ÷ 388 = 210 lb.
(Mod. E. N. Formula)[c]—48,000 ÷ 388 = 124 lb.

[a] Information by: R. G. Watts, Asst. Chief Engineer, Magnolia Petroleum Co., Dallas, Texas.
[b] E. N. Formula:

$$\text{Safe Load} = \frac{2WH}{S + 0.1}$$

[c] Mod. E. N. Formula: (Eytelwein) for heavy piles:

$$\text{Safe Load} = \frac{2WH}{S + 0.1\left(\frac{\text{Weight of Pile}}{\text{Weight of Hammer}}\right)}$$

basis for comparing these results is obtained. Only three of the tests included the redriving of the piles after a period of rest. Although these rest periods were comparatively short, varying from 15 to 24 hr, the safe load, in each case, practically doubled. One pile, on which a load test was carried out after 12 hr rest, increased approximately 75 pct. It is my opinion that 24 hr rest is insufficient to attain the maximum amount of freeze, but what time interval is actually required can only be determined by further and more extended tests.

FREEZING ACTION AND POSSIBLE SAFE BEARING CAPACITY

Terzaghi states that this freezing action

> . . . is thought to be caused by the squeezing of a certain quantity of water out of the soil beneath the point of the pile in driving. The water escapes toward the surface through the space between the pile and the ground and forms a film acting as a lubricant against the side of the pile. During a period of rest, the film of water is gradually absorbed by the soil and the full static pile friction develops.[3]

It is possible that this action is aided by the settling of the coarser, noncohesive sands and gravels against the side of the pile during the driving period while the surrounding earth is being agitated. Upon stabilizing, these materials produce an increase in the coefficient of friction of the surface in contact with the pile. This property of sands to rise to, and tighten at, the surface when agitated is well known.

Regardless of the cause of this setting its actual occurrence is undeniable. If structures are built on piles driven into saturated silts, clays and fine sands, on the basis of driving tests which do not take into consideration this set, the provider of funds for them need have no worry concerning their possible failure, but he should (especially with piling costs as at present) examine his bank balance very carefully.

Until further and more comprehensive tests are made which will provide definite knowledge of the total increase in bearing capacity because of this freezing action

and the extent of time required to reach this maximum, designs will have to be based on known safe loading capacities which are probably very conservative. Magnolia, on their first location, used a loading of 50,000 lb per 15 in. od steel pipe piles with a penetration of about 98 ft. This is a unit load of 130 lb per sq ft of contact surface. Table 3 shows the test on one pile of a group of three driven at this location in the preliminary investigation. It is probable that a load of 50,000 lb per pile was reached, if not exceeded during drilling operations. About one year after the installation of this foundation, the piling were pulled. A pull of over two hundred thousand pounds could not loosen the piling, even in conjunction with a jet extending down approximately one half of the pile penetration. Only by lowering the jet to within about 25 ft of the pile tip could it be removed.

It can safely be assumed that the force required to extract the pile, less its actual

TABLE 4—*Pile Test—T-3*[a]

Company: Magnolia Petroleum Company.
Location: See Fig 2; water, 21 ft deep; Gulf Floor, o.o.
Pile: 15-in. od steel pipe, 1 in. wall, 136 ft long, 149.5#/lin. ft; welded joints; total weight 20,332 lb.
Hammer: No. 1 vulcan steam; total weight 10,200 lb; ram, 5,000 lb, stroke, 36 in.

Depth of Penetration, Ft	Increment, In.	Blows	Penetration per Blow, In.	Safe Load, Tons, E. N. Formula	Safe Load, Tons, Mod. E. N. Formula
17.0		Weight of pile only			
23.75		Dropped pile 7 ft			
30.0	75.0	22	3.41	4.3	3.9
35.5		Broke through into mud and dropped			
42.0	78.0	21	3.71	3.9	3.6
49.0	84.0	20	4.20	3.5	3.2
56.0	84.0	29	2.90	5.0	4.5
59.5	42.0	30	1.40	10.0	8.2
63.5	48.0	30	1.60	8.8	7.4
66.0	30.0	30	1.00	13.6	10.6
69.5	42.0	30	1.40	10.0	8.2
72.0	30.0	30	1.00	13.6	10.6
75.5	42.0	30	1.40	10.0	8.2
77.0	18.0	30	0.60	21.4	14.7
80.0	36.0	51	0.76	17.5	12.7
83.5	42.0	60	0.70	18.8	13.4
86.0	30.0	50	0.60	21.4	14.7
88.5	30.0	50	0.60	21.4	14.7
92.17	44.0	150	0.29	38.5	21.1

Contact area of pile:
$15/12 \times 3.1416 \times 92.17 = 362$ sq ft.
Safe load per sq ft contact area:
(E. N. Formula)—$77{,}000 \div 362 = 212$ lb.
(Mod. E. N. Formula)—$42{,}200 \div 362 = 116$ lb.
Soil classification: 0 to 30 sand and silt (no mud)
30 to 35 soft mud
35 to 88 blue gumbo (clay) stiffness increasing with depth
88 to 92.2 very stiff

[a] Information by: R. G. Watts, Asst. Chief Engineer, Magnolia Petroleum Co., Dallas, Texas.

TABLE 5—*Pile Test—T-4*[a]

Company: Magnolia Petroleum Company.
Location: See Fig 2; water, 20 ft deep; Gulf Floor, o.o.
Pile: 24-in. od steel pipe, 160 ft long, 125.5#/lin. ft; welded joints; total weight, 20,080 lb.
Hammer: No. o Warren-Vulcan steam; total weight, 16,250 lb; ram 7,500 lb; stroke, 39 in.

Depth of Penetration, Ft	Increment, In.	Blows	Penetration per Blow, In.	Safe Load, Tons, E. N. Formula	Safe Load, Tons, Mod. E. N. Formula
43.7		Weight of pile only			
48.7		Hammer free on pile			
60.7	144	50	2.88	8.2	7.7
63.7	36	25	1.44	15.8	14.2
67.7	48	25	1.92	12.1	11.1
71.7	48	25	1.92	12.1	11.1
74.2	30	25	1.20	18.7	16.5
77.7	42	25	1.68	13.7	12.5
83.2	66	50	1.32	17.2	15.3
85.7	30	25	1.20	18.7	16.5
86.7	12	25	0.48	42.0	32.5
88.2	18	25	0.72	29.7	24.6
88.7	6	25	0.24	71.7	47.8
89.2	6	25	0.24	71.7	47.8
90.2	12	25	0.48	42.0	32.5
90.7	6	25	0.24	71.7	47.8
91.7	12	25	0.48	42.0	32.5
92.2	6	25	0.24	71.7	47.8
92.9	8	25	0.32	58.0	41.2
93.7	7	25	0.28	64.2	44.3
94.2	6	25	0.24	71.7	47.8
94.7	6	25	0.24	71.7	47.8
95.7	12	25	0.48	42.0	32.5
97.2	18	25	0.72	29.7	24.6
98.2	12	25	0.48	42.0	32.5
98.7	6	25	0.24	71.7	47.8
99.7	12	25	0.48	42.0	32.5
100.2	6	25	0.24	71.7	47.8
100.7	6	25	0.24	71.7	47.8

Contact area of pile:
$2 \times 3.1416 \times 100.7 = 673$ sq ft.
Safe load per sq ft contact area:
(E. N. Formula)—$143{,}400 \div 632 = 227$ lb.
(Mod. E. N. Formula)—$95{,}600 \div 632 = 151$ lb.

[a] Information by: R. G. Watts, Asst. Chief Engineer, Magnolia Petroleum Co., Dallas, Texas.

weight, is a close approximation of the static friction which can be used as a maximum value in design. Completely discounting the area of contact surface eliminated by the jetting action, the unit force required to pull the pile amounted to at least 500 lb per sq ft. It is probable, considering the surface area on which friction was partially, or totally, destroyed by the jet, that the static friction amounted to 750 lb or more per square ft. If such is the case, after maximum set is obtained, then design loading can be considerably increased, say to 250 lb per sq ft of contact surface, and still retain a safety factor of 3 to 1. This would bring about large savings in material and erection costs.

TABLE 6—*Pile Test—T-5*[a]

Company: Magnolia Petroleum Company.
Location: See Fig 2; water, 26 ft deep; Gulf Floor 0.0.
Pile: 8⅛-in. od steel pipe, 132 ft long, 38.42#/lin. ft.
Hammer: No. 0 Warren-Vulcan steam; total weight, 16,250 lb; ram, 7,500 lb; stroke, 39 in.

Depth of Penetration, Ft	Increment, In.	Blows	Penetration per Blow, In.	Safe Load, Tons, E. N. Formula
0.5		Weight of pile		
3.75		Hammer free on pile		
10.0	75	25	3.0	7.9
11.5	18	25	0.72	29.8
13.75	27	50	0.54	38.1
17.0	39	25	1.56	14.7
22.0	60	25	2.4	9.8
29.5	90	25	3.6	6.6
37.5	96	25	3.84	6.2
44.5	84	25	3.36	7.0
49.5	60	25	2.4	9.8
57.5	96	25	3.84	6.2
63.5	72	25	2.88	8.2
83.5	240	100	2.4	9.8
88.0	54	25	2.16	10.8
91.5	42	25	1.68	13.7
94.0	30	25	1.20	18.8

Contact area of pile:

$$\frac{8.125}{12} \times 3.1416 \times 94 = 200 \text{ sq ft.}$$

Safe load per sq ft contact area:
(E. N. Formula)—37,600 ÷ 200 = 188 lb.
Soil classification:
Very stiff clay from depth of 4 to 10 ft.
Very soft layer 14 to 38 ft.
Stiffening continuously below.

[a] Information by: R. G. Watts, Asst. Chief Engineer, Magnolia Petroleum Co., Dallas, Texas.

TABLE 7—*Pile Test—T-6*[a]

Company: Stanolind Oil and Gas Company.
Location: See Fig 2; water, 9 ft deep; Gulf Floor 0.0.
Pile: 100 ft creosoted fir; diam. 10 ft intervals from tip: 0 ft (tip) 6.84 in.; 10 ft 8.91 in.; 20 ft 10.66 in.; 30 ft 12.18 in.; 40 ft 12.97 in.; 50 ft 14.00 in.; 60 ft 14.56 in.; 70 ft 14.88 in.; 80 ft 15.12 in.; 90 ft 15.75 in.; 100 ft (butt) 16.63 in. Computed weight of piling, 3,200 lb (approx.).
Hammer: 50C Super Vulcan; total weight, 11,845 lb; ram, 5,000 lb; normal stroke, 15½ in.; equivalent stroke, 3 ft.
Load test: Made with Tinus Olson 100 ton hydraulic compression machine between pile and build-up girder, framed between four hold-down piles.

Depth of Penetration, Ft	Increment, In.	Blows	Penetration per Blow, In.	Safe Load, Tons, E. N. Formula
20.8		Weight of pile		
52.0		Hammer free on pile		
55.0	36.0	10	3.6	4.1
58.5	42.0	10	4.2	3.5
62.0	42.0	10	4.2	3.5
64.5	30.0	10	3.0	4.8
67.1	31.2	10	3.12	4.7
68.8	20.4	10	2.04	7.0
70.9	25.2	10	2.52	5.7
72.5	19.2	10	1.92	7.4
73.8	15.6	10	1.56	9.0
75.3	18.0	11	1.64	8.6
76.8	18.0	10	1.80	7.9
78.0	14.4	10	1.44	9.7
79.3	15.6	11	1.42	9.9
80.8	18.0	10	1.80	7.9
81.9	13.2	11	1.20	11.5
82.9	12.0	10	1.20	11.5
83.8	10.8	10	1.08	12.7
84.8	12.0	10	1.20	11.5
85.6	9.6	10	0.96	14.1
86.6	12.0	10	1.20	11.5

Approximate contact area of pile—280 sq ft.
Safe load per sq ft contact area:
(E. N. Formula)—23,000 ÷ 280 = 82 lb.
Load test applied after pile set 24 hr:

Load, Tons	Applied, Hr	Settlement, In.	Accumulative Settlement, In.
10	36	0	
20	6	3/32[b]	
30	6	0	3/32
40	1/12	3/32	3/16
41	1/12	1/4	7/16
41–50	Movement continuous		

By load settlement graph, indicated safe working load: 40,000 lb.
Safe load per sq ft contact area:
(load test) 40,000 ÷ 280 = 143 lb.

[a] Information by: John Evans, Stanolind Oil & Gas Co., Tulsa, Okla.
[b] Apparent settlement attributed to compression in top fibers of unevenly sawed pile.

To obtain a working knowledge of this probable increased bearing capacity after maximum freeze an actual static load test would be required. A suggested load test is to drive four pilings in the form of a square, install a deck and erect a 2000-bbl tank thereon. After driving, the piling should be permitted to set for at least two weeks before the test is started. By alternately pumping in and withdrawing water, allowing the structure to remain in both loaded and unloaded state for several hours; increasing the amount of water each time the tank is reloaded, a close approach to actual working conditions will be obtained. When full of sea water the tank and superstructure will impose a load of over 180,000 lb per pile which (unless pile diameter and length is excessive) should produce some settlement, and possibly a failure. The results, thus obtained, correlated with the analysis of a soil technician will provide a true basis for design.

TABLE 8—*Pile Test—T-7*[a]

Company: Kerr-McGee Oil Industries Inc., Oklahoma City, Okla.
Location: See Fig 2; water, 18 ft deep; Gulf Floor 0.0.
Pile: 10 in. od steel pipe, 120 ft long.
Hammer: No. 1 Vulcan steam; total weight, 10,200 lb; ram, 5,000 lb; stroke 36 in.

Depth of Penetration, Ft.	Increment, In.	Blows	Penetration per Blow, In.	Safe Load, Tons, E. N. Formula
33.5		Weight of pile		
38.5		Pulled with pile line		
39.1		Weight pile with hammer		
42.0	35	11	3.2	4.6
69.3	328	10	32.8	0.5
72.6	39	10	3.9	3.8
75.5	35	10	3.5	4.2
78.8	39	10	3.9	3.8
80.7	23	10	2.3	6.2
82.8	25	10	2.5	5.7
84.6	22	10	2.2	6.5
86.7	25	10	2.5	5.7
88.5	22	10	2.2	6.5
90.2	20	10	2.0	7.2
92.0	20	10	2.0	7.2

Contact area of pile:
$10/12 \times 3.1416 \times 92 = 241$ sq ft
Safe load per sq ft contact area:
(E. N. Formula)—$14,400 \div 241 = 60$ lb.
Pile permitted to set 23 hr before driving resumed.

92.5	6	10	0.6	21.4
93.0	6	9	0.67	19.5
93.5	6	8	0.75	17.6
94.0	6	9	0.67	19.5
94.5	6	9	0.67	19.5
95.0	6	8	0.75	17.6
95.5	6	8	0.75	17.6
96.0	6	8	0.75	17.6

Contact area of pile:
$10/12 \times 3.1416 \times 96 = 252$ sq ft
Safe load per sq ft contact area:
(E. N. Formula)—$35,200 \div 252 = 140$ lb.

[a] Information by: Tom Seale, Chief Engineer, Kerr-McGee Oil Industries, Oklahoma City, Okla.

Soil Mechanics

There has been little, if any, use of soil mechanics in the design of offshore structures up to the present time. This science, which in recent years has attained full recognition as an important branch of engineering, can be profitably employed in preliminary investigations of structures to be built on the continental shelf. An examination of the materials encountered to determine water content, clay content, water plasticity ratio of clays, cohesion in silts and clays, and other tests made by qualified soil technicians can provide a close check of the results of driving and load tests, and discover unconformities in the various layers which would lead to a correct determination of piling lengths and give other assistance to the proper solution of the problem. After the erection and use of the first structure in any given area additional installations can no doubt be safely designed by the correlation of test borings in conjunction with the driving of a single test pile.

Mat-type Foundations

The foregoing has dealt with piling-type foundations only. On the Louisiana continental shelf it is probable that no other types are applicable, with the possible exception of a small area close to shore where the water is shallow and wave action is minimized by protecting reefs. Drilling barges have been successfully used, where the depth of water is commensurate with their draft, by first placing a compacted

shell mat over the area on which the barge is placed. Trouble has been experienced with tilting of drilling barges used on the natural Gulf floor without providing a mattress. It is probable that if the wave action was considerable in amount and directed continuously against one side of the barge for an extended period, sufficient undercutting would result to endanger the operation, even with the use of a mat.

In the case of a drilling barge considerable amount of the total load is supported by the buoyancy of the partially submerged pontoons and only a small portion is carried by the earth below. If an attempt were made to use a nonbuoyant mat, the entire load would be imposed upon the soil directly below it. The area of the mat should be sufficient to stay within the safe bearing capacity of the Gulf floor. Unquestionably this bearing capacity is, with a few exceptions, quite low. Furthermore, with mats heavily loaded and large in area pressures are carried down to a considerable depth and, as evidenced by some of the pile tests given in the tables, could easily reach into an underlying soft compressible stratum. The result would be considerable settlement which, if unequal, would endanger the structure.

TABLE 9—*Summary of Test Pile Data*

Test No.	Pile			Total Penetration before Rest, Ft	Safe Load	Safe Load Lb per Sq Ft Contact Surface	Rest Period Hr	Total Penetration after Redriving, Ft	Safe Load	Safe Load Lb per Sq Ft Contact Area
	Material	Size, In., Od	Length							
T-1	Steel pipe	7	112	80.0	7.71[a]	105	15	83.6	15.65[a]	204
T-2	Steel pipe	15	120½	97.0	13.9[b]	73	24	98.75	24.0[b]	124
T-3	Steel pipe	15	136	92.17	21.1[b]	116		Not included		
T-4	Steel pipe	24	160	100.7	47.8[b]	151		Not included		
T-5	Steel pipe	8⅛	132	94.0	18.8[a]	188		Not included		
T-6	Creo. fir	7 tip 16 butt	100	86.6	11.5[a]	82	24	Load test		143
T-7	Steel pipe	10	120	92.0	7.2[a]	60	23	96.0	17.6[a]	140

[a] Engineering News Formula (Weight of pile less than weight of ram).
[b] Mod. Engineering News Formula (Heavy piles).

Remainder of the Gulf Coast Continental Shelf

The above remarks have applied specifically to the Louisiana continental shelf inasmuch as all offshore exploratory drilling has, so far, been concentrated in this area. Until these operations are extended into other sections, preliminary investigations made, and structures actually installed, only general inferences concerning them can be made. Apparently, conditions similar to those encountered adjacent to Louisiana will apply along the coasts of Mississippi and Alabama. However, as we continue into the extensive shelf off Florida we enter an area very different. Here the surface is largely sand, shell and coral and the bearing capacities will be much greater. If coral is encountered, as in one location made offshore of the Florida Keys, the full strength of the pile acting as a column will be developed.

The remaining portion of the Gulf Coast Continental Shelf—that part bordering the state of Texas—varies considerably from the others, at least insofar as surface conditions are concerned. At the southern extremity the continental shelf is much narrower and steeper, in fact along practically the entire Texas coast the slope of the shelf from the shore to the 30-ft depth contour is much sharper than is general elsewhere. The upper layer of the Pleistocene in this area consists of clay and marl, interbedded with lentils of clay. Along the coast it is reached at comparatively shallow depths, usually about 6 to 10 ft. The overburden consists largely of wind-blown sands and silts. The rivers of Texas are not

heavily loaded with sediment, except during flood stages, and for this reason it can be assumed that the alluvial deposits found on the shelf will not be of great thickness. If the upper layer of the Pleistocene can be reached by piling, comparatively good bearing values should be obtained. However, preliminary investigations prior to the design and construction of the first installations in this area should be very thorough as there is great danger of encountering a layer of loose unconsolidated sands, which would prove a possible cause of failure unless proper provisions are made. Detailed knowledge of the characteristics of the continental shelf in this region must await actual subsurface investigations.

Conclusion

Although the available data are very limited, such information as we have points very definitely to the imperative need of securing complete knowledge concerning the conditions at the site of each job. The mere driving of test piling is not enough. Load tests of piling groups should be carried out and the knowledge thus obtained, in conjunction with soil analyses from actual borings should be used as the basis design. Such procedure is warranted by the financial outlay required to construct even the simplest structure in relatively deep water at considerable distances off shore and the tremendous loss which would be experienced if a failure occurred. The large sums which are often expended without acquiring such knowledge is a source of amazement. Actually, money spent for thorough preliminary research will generally prove to be far from wasted as it will usually lead to improvements in design, which will decrease the cost of material and construction in an amount far in excess of the expense of the investigation.

Acknowledgments

Wherever possible, suitable references as to the source of information have been given. Particular thanks is due Mr. H. A. Huesmann, Chief of the Soil Section, U. S. Engineers, New Orleans District, New Orleans, Louisiana, for information and suggestions he has given.

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Important Considerations in Marine Construction

By F. R. Harris* and Harry Gard Knox†

(Tulsa Meeting, October 1947)

Abstract

This paper covers some of the problems presented to the oil industry in the drilling of oil wells in the open waters of the Gulf of Mexico. The hazards, delays and relative costs of offshore drilling are reviewed and various forms of drilling platforms discussed.

The requirements of the offshore drilling rig are summarized together with the principal items affecting the cost of construction. Sea waves and their size and characteristics as affecting offshore platforms are reviewed.

Drilling platforms are classified as fixed, or fixed and floating. Fixed platforms of the conventional cofferdam and pile-supported type are discussed together with their good points and their limitations. The desirability is pointed out of eliminating as much offshore work as possible where operations are subjected to constant and expensive delay and substituting therefor the prefabrication of structures ashore or in sheltered waters. Marked economy will come with the standardization of offshore rigs and special means of transporting them to the site.

Several types of structure which are partly pile-supported and partly buoyancy-supported are discussed and their possibilities of future usefulness commented upon.

General Considerations

The predominant attribute of offshore drilling equipment is that it must be equal to the job in hand. We therefore give first thought to the matter of adequacy.

In view of the probable depth of drilling, the investment involved and the per diem labor costs, it is assumed heavy modern drilling equipment will be employed. In order to use such equipment efficiently, the working deck must be ample in size and strength and supported so as to be relatively free from motion and from green seas even in heavy storms. These requirements necessitate a high and rigid land-based support for the drilling rig and machinery with plenty of space for supplies, such as pipe, mud, water and fuel, with reserves for days when transportation from shore is impracticable. In offshore rigs the crew will be housed on board in comfortable quarters, probably air conditioned and equipped with a galley and refrigerated food storage.

An important consideration will be the ability to transfer stores and crew to and from the rig in all but the heaviest weather and the platforms must be protected from the impact of supply vessels when alongside. It will be essential to maintain continuous communication with shore by radio or cable, not forgetting the possibility of a helicopter landing space for the transfer of crew and light stores as well as a means of general communication. Whatever structure is constructed must be secure from storms of hurricane force and a safe place for the operating crew to work. If the well comes in, the drilling rig will presumably be removed and a small but rugged pile-supported platform will remain to carry the Christmas tree with safe working space around it. It will be protected from damage on all sides by buffer piles or dolphins.

It is assumed that the flowing oil will be piped to storage tanks in the vicinity of the well. An individual tank for each well or a

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battery of tanks to handle a group of neighboring wells can be used. The tanks themselves will probably be carried on pile-supported structures although floating barges, or floating oil tanks in some situations may be a possibility. Oil stored offshore in the vicinity of the wells will presumably be transferred at frequent intervals to tankers or in some cases pumped ashore through rigid or flexible pipe lines. The location of the field, its distance offshore and the depth of water will determine the method of transfer chosen.

Cost

Hand in hand with the adequacy of the modern rig comes the consideration of its cost of construction and cost of operation. Working platforms of cofferdam or pile-supported construction built in conventional manner require virtually complete assembly at the offshore site. There will be involved the transportation of labor and material entering into the structure, the fair weather erection costs plus long and expensive foul weather delays.

Many of the uncertainties of offshore construction can be minimized by doing as much of the work ashore as possible in the form of prefabricated elements or units. There is wide latitude in the methods which may be used in transporting prefabricated structures to the site and finally placing them on the bottom and completing the erection. By extending the shore-based prefabrication and reducing the offshore construction, foul weather delays and the high costs of offshore assembly work and marine insurance can be enormously reduced.

In any type of structure the cost of its ultimate removal and use on another job or the availability of salvaged material for re-use are important considerations.

Wind and Wave

Waves in the Gulf of Mexico are of the deep water wind-wave type but, depending upon the velocity, duration and fetch of the wind, they may be quite high. In length they are relatively short compared, for example, to the long rollers of the Pacific Ocean. Deep water waves 25 ft high and 400 ft or more in length might be expected to occur in the Gulf. Once a deep sea wave reaches water about one-half wave length deep, its characteristics gradually change to those of a shallow water wave,—the height and length of the wave decrease independently of each other, and the speed of travel slows down. As the water continues to shoal, the wave fronts swing until they parallel the shore line and ultimately the rollers rise and arch over towards the beach as the familiar surf.

In 100 ft of water or less, waves will seldom exceed 20 ft in height and even this size of wave will be exceptional. In shoal water it is usually assumed that two-thirds of the wave height is above the still water line and one-third below so that the crest of a 20-ft wave will rise about 13 ft above the still water level and the trough will sink about 7 ft below it. The deck of an open structure erected offshore in the Gulf should therefore be raised at least 20 ft above the still water line. The impact of green sea waves upon any structure exposed to them can be tremendous but this phase of the wave problem is not included in this paper.

During any severe blow the level of the sea along the coast may be raised by an on-shore wind and thus lift the wave crests with respect to any shore-based structure. The total rise will depend upon the wind velocity and direction, and the proximity and shape of the nearby shore line. The closer to shore and the more complete the enclosure formed by the land, the greater the effect on the water level will be. Likewise, in the center of a hurricane, even in the open sea, the water level is a foot or two higher than the surrounding water. The usual change in mean level induced by either of these causes in open water off the Texas-Louisiana coast will not be more

than 2 to 4 ft. On the other hand, in the Harbor of Galveston, for example, a hurricane has reportedly raised the water level by as much as 10 or 15 ft.

Along the Texas-Louisiana coast the most dangerous gales accompanied by heavy seas come out of the southeast, especially during the winter months. From November to April "northers" blow up from the northwest and north. They are violent but as they blow offshore the wave action is less. Gales in the sector from northwest to south are extremely rare. Tropical hurricanes, with wind velocities of 125 mph or more, occur occasionally, the greatest frequency being between August and October. At a particular point the wind during the passage of a cyclonic storm may blow from any direction but the green waves kicked up are not as powerful as those accompanying southeasterly gales of long duration.

Types of Offshore Structures

The terrain first facing exploitation, we understand, lies off the Louisiana and Texas coasts from the mouth of the Mississippi River to Brownsville, Texas. It is hard to predict to what sea depths well drilling may ultimately proceed, perhaps up to 120 ft or more, but it is almost certain that the first efforts will lie within 60 ft of water. As an indication of the Gulf area involved the following tabulation is pertinent:

Distance Offshore to 10 and 20 Fathom Contours

Location	In Nautical Miles	
	10 Fathom	20 Fathom
Brownsville	4	15
Corpus Christi	5	20
Matagorda Bay	10	27
Galveston	25	50
Port Arthur	35	65
Atchafalaya Bay	35	48
Terrebonne Bay	20 to 10	32
West Side Mississippi Delta	8	16

The offshore area between the shore line and the 10-fathom curve from the Mississippi Delta to the Rio Grande represents an area of about 11,000 square nautical miles.

In discussing various types of drilling platforms which at this stage of development appear to hold promise in the offshore field, there are two headings under which they will be considered: (1) fixed; (2) fixed and buoyant.

Fixed Drilling Platforms

The first form of drilling platform which suggests itself for use close inshore is the sheet pile cofferdam carried up to a level well above storm waves. This form of artificial island may have its uses in water up to a depth of about 25 ft, preferably where the work of construction can be carried on behind some protected headland or reef. Driving sheet piles and providing the fill in a structure in the open Gulf will, because of wind and wave, seldom be a simple operation. Delays will be many and costly while the hazards to working personnel will be great. It should be pointed out that the sheet piling will require unusually deep penetration into the soil, particularly if the bottom consists of the fine silty sediments typical of the area. The pounding of sea waves against the solid obstruction of the vertical bulkhead tends to scour out the bottom at the base of the piles and this scouring action may carry down so deeply as to undermine the supporting sides of the cofferdam. Part of the breaking waves will also cascade upward and tend to inundate the working area.

As most, if not all, offshore structures will require removal as obstructions to navigation after they have served their purpose, the dismantling of a cofferdam will also be an expensive operation. The problems and costs involved in the creation and removal of an artificial island of this type are well-known to the oil industry and will not be further discussed.

A second type of structure which may find some uses in open Gulf waters is the

conventional type of platform supported on piles of wood, concrete or steel. It will be a time-consuming and costly structure. Much will depend upon the weather encountered, the weight, mooring and other seagoing qualities of the equipment used. At best the driving of piles from a rolling pile driver will be slow and expensive. Once a start has been made on the platform the use of a land-based pile driver may permit the continuation of the structure with less delays than those inevitably involved when using floating equipment.

The deck of the pile-supported structure must be carried well above the crests of probable waves. Pile-supported structures are, however, relatively free from the scouring action involved by waves breaking against solid bulkheads and by permitting the waves to roll through the open piling without breaking, the deck will be drier than in the case of the solid-walled cofferdam. Tubular members offer much less resistance to impinging waves than flat sided members such as *H*-beams. In order to secure a platform free from movement, deep cross bracing is necessary. The ultimate removal of the pile structure will be a tedious and expensive operation again at the mercy of the weather. Two or more conventional pile-supported drilling platforms have already been constructed in the open Gulf and at least two have been salvaged.

The caisson-supported structures being used in Lake Maracaibo in Venezuela represent a specialized form of structure which is being used in the deep and relatively protected waters of the Lake. This type of structure is well adapted to the local conditions where it is being used but is hardly applicable to drilling operations off the southern coast of the United States.

Both the cofferdam and the pile-supported platform heretofore mentioned contemplate the transportation of piles and other structural material to the site piece by piece and assembly under whatever weather conditions exist from day to day throughout the construction period. The drilling equipment and machinery will also have to be landed on the platform from rolling barges, piece by piece, and installed at sea. The more the problem is studied the more evident it becomes that whatever fabrication work can be done ashore or in sheltered water and transported to the site in assembled form will reduce the handicaps of foul weather working and will in general expedite the completion of the structure and reduce its cost.

Further economy will come with the standardization of platform types which will ultimately be built, not singly as custom-made products, but on a limited mass-production basis. We may look forward to the time when the fully equipped platform is transported as a single unit on pontoons or barges especially designed for the purpose. As soon as platforms can be constructed in tens or twenties special transporting devices can easily be justified and installation time at sea reduced to the matter of a few days. As soon as drilling is completed a platform in this class would be picked up and moved to a new location.

In a recent operation a heavy platform was transported to the site in relatively large pre-assembled units. The piling was carried in rigidly cross-braced tubular jackets ready to be dropped and driven, and the prefabricated units were transported and placed in position by conventional flat-deck and derrick barges. This certainly seems a step forward along practical and economic lines and the nine-day pile driving period exemplified the reduction in field work.

As a further step towards complete assembly Fig 1 is a schematic idea of a drilling platform towed to site on special pontoons as a single unit. In area the deck can be 150 by 100 ft or as much larger as necessary. The transporting pontoons are constructed somewhat like small floating dry docks. Assembled in a sheltered harbor, the drill-

ing deck with its supporting tubular legs will, when ready, be picked up by the transfer pontoons and towed to location. The structure will itself be thoroughly seaworthy for any weather but smooth water is desirable for towing and for a few hours of pile driving. Upon arrival at destination a few of the piles already contained in the supporting jackets between pontoons will be released to act as spuds to hold the rig in position. The pontoons will then be flooded until the drilling deck is at about its final elevation. At this level the main pontoons will be completely submerged with depth of sinkage and stability controlled only by the small water planes of the cylindrical towers. The cross section of the towers is so small that waves can freely pass between them and the rise and fall of the rig due to wave action will be slight.

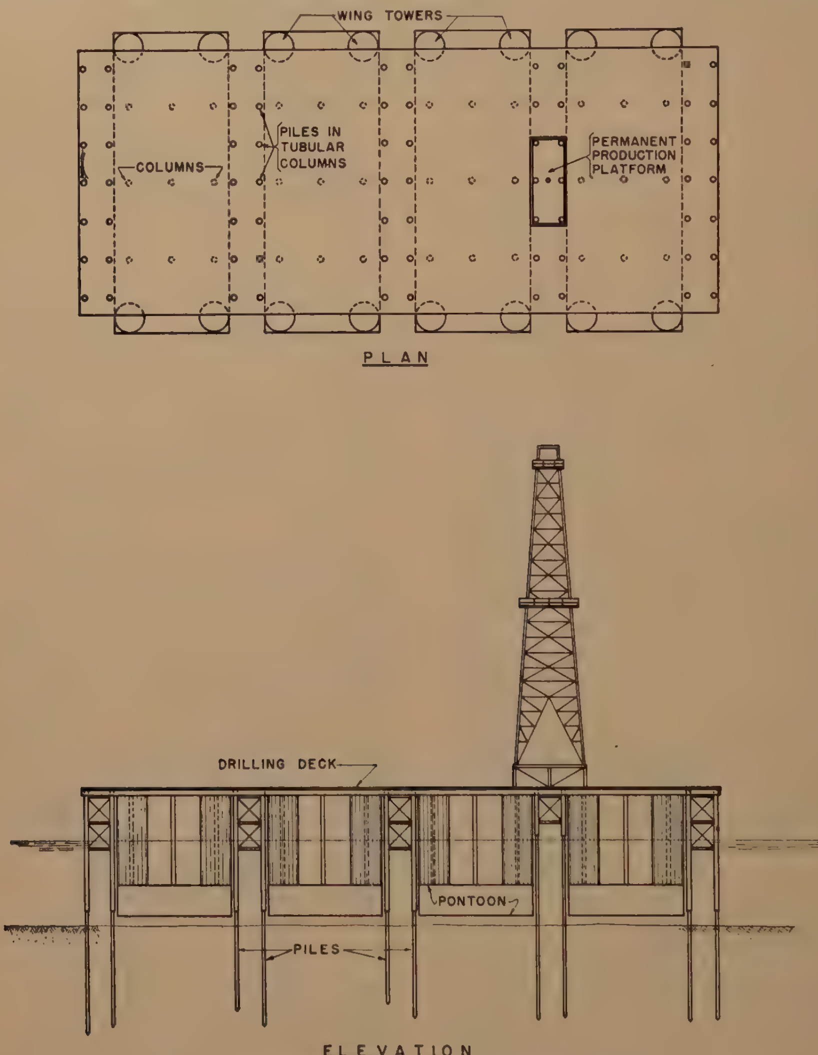

FIG 1—SCHEMATIC DRAWING OF A DRILLING PLATFORM.

More piles will now be released and driven to final penetration. When a sufficient number of piles have been driven the deck will be leveled up by adjusting the water levels in the compartments of the supporting pontoons and when in desired position the motion between the floating platform and the fixed piles will be stopped by hydraulic jacks or clamps. The platform will then be rigidly bolted or welded to the piles. In this manner the platform will be transferred from water-borne to land-borne support and the barges then further flooded and withdrawn. To carry the working loads, additional piles will be driven at as many points as necessary in the spaces vacated by the pontoon floats. The pontoons will require careful design to ensure adequate buoyancy and stability at various degrees of flooding and thorough control while partially submerged. Provision is made for a small permanent platform which will remain behind when the main rig is removed.

When the time comes to remove the platform, the pontoons will be towed to the site, then partly submerged and hauled into place. The supporting piles can be pulled at the same time the lift of the pontoons is increased by slowly unwatering them. At some moment when the uplift of the pontoons becomes sufficient to break the hold of the remaining piles the structure will be afloat. Continued unwatering of the pontoons will raise their decks above the water line to a freeboard ready for towing and at this level the drilling deck will be high above the Christmas tree.

This design has not been carried beyond the preliminary stage and it is presented here merely to illustrate one type of structure which can be placed in an offshore location and removed with a minimum of time and cost. The special transporting barges can hardly be justified for one platform but when repeat installations are started the pontoons are available to move on to the next job as soon as one platform is established at sea. By some such expedient the time of setting up and removing platforms can be greatly expedited and the work of fabrication shifted from the rough and tumble surroundings at sea to efficient working conditions in a sheltered harbor or on shore.

Fixed and Buoyant Platforms

There seems to be another field for the possible use of drilling platforms which are partially pile-supported and partially supported by buoyancy. These combination structures naturally fall into two groups; first, those in which the entire drilling deck is partially supported by piling and partly by buoyant pontoons. The second type is one in which the deck carrying the essential drilling equipment is a fixed pile-supported platform while many of the accessories are carried nearby on a floating structure where wave motion is not too objectionable.

A platform of the first type has been carried fairly well along in the design stage and presents one solution to the offshore-drilling problem, Fig 2. The rig consists of a heavily constructed drilling deck of whatever size is deemed necessary for accommodating the drilling equipment, the necessary supplies and the crew. The deck is carried permanently on hollow tubular columns and towers by heavy submersible pontoons constructed on the principles of a floating dry dock. The columns contain steel piles, and the towers supply the needed stability, at the same time forming useful storage tanks. The rig is erected in a sheltered harbor and all of the major items of equipment installed. It is a thoroughly seaworthy form of vessel with strength and stability for any weather.

To facilitate transferring the structure from water-borne to pile-borne support it will be towed to site in calm weather. When in position on location, a few piles acting as spuds are dropped down in the open bottomed tubular columns which carry the drilling deck. The pontoons, which contain

numerous compartments, are then flooded until the drilling deck is leveled off at approximately its desired elevation. At this level the pontoon hulls will be submerged well below the water line and thus below the active effect of surface waves while the large cylindrical towers afford the necessary stability and buoyancy control. Piles are now released through more of the tubular supporting columns in which they are carried and as rapidly as possible are driven to the desired penetration. Motion between the piles and the floating structure is then stopped by hydraulic jacks or by friction

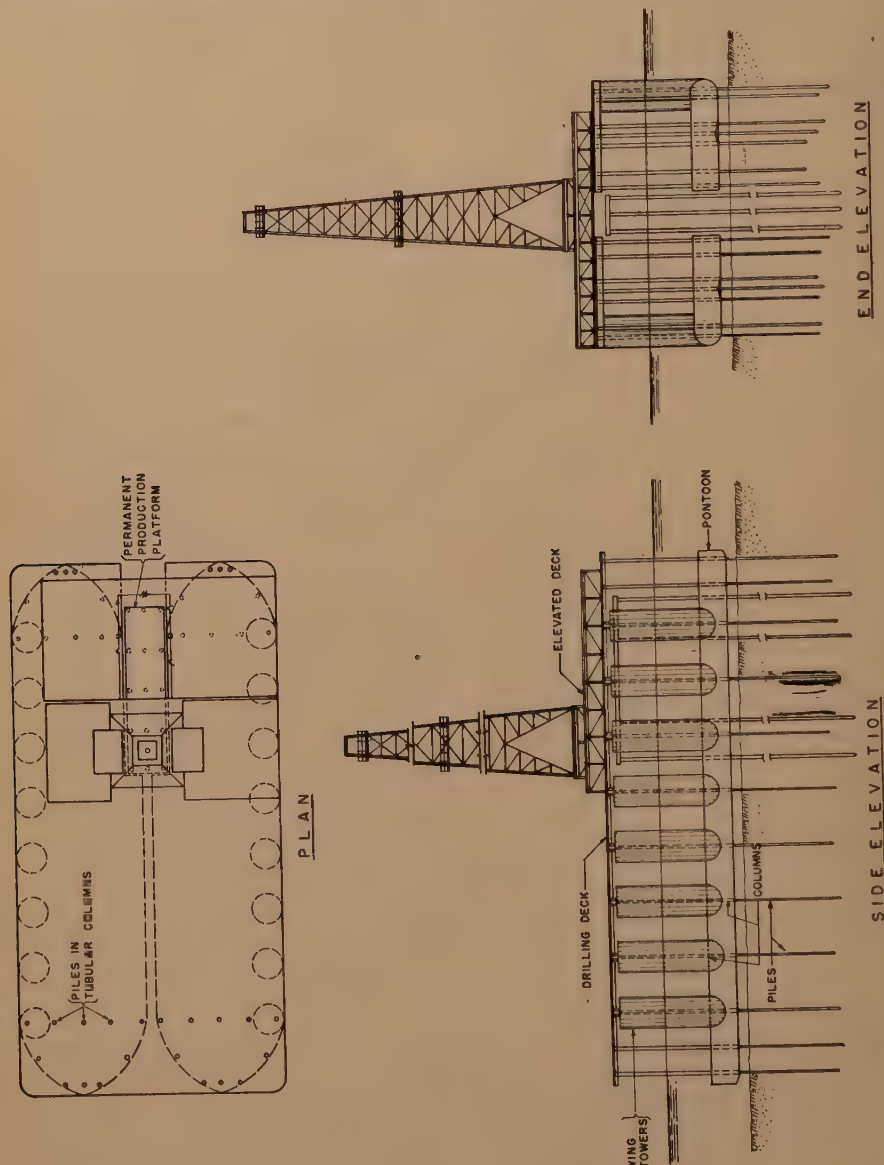

FIG. 2—SCHEMATIC DRAWING OF A DRILLING DECK SUPPORTED PARTLY BY PILING AND PARTLY BY BUOYANT PONTOONS.

clamps and the deck then rigidly secured to the supporting piles as described in the case of a previous rig.

The lift of the buoyant pontoons, which remain with the structure during the entire drilling period, is adjusted by expelling ballast water to carry a large proportion of the weight of the structure. Under these conditions, the number of piles can be based upon the requirements of holding the rig in position against the action of the sea rather than by the requirements of supporting the weight of the drilling deck entirely on piling. The advantage of using buoyancy and eliminating piling is obvious when it is considered that in a completely pile-supported structure many heavy items of equipment cannot be skidded into working position until after the piles have been driven and finally secured to the deck framing.

At the drilling end of the platform a slot is provided for a small permanent platform which, in the case of a flowing well, remains after the main portion of the drilling platform is floated and removed to a new location. By eliminating practically all field work and by moving the rig from well to well the economy of installing and removing this type of structure should far outweigh the original cost of its construction.

The design of a rig of this type is not simple but all of the principles are well-known and have been thoroughly worked out in connection with the construction of ships and floating dry docks. In condition for towing, the rig is designed to take wind pressures up to hurricane force and once on location it is figured to withstand any weather. The structure has been computed for weight, center of gravity, stability and structural strength at all stages of surface operation and submergence.

Any such structure, while afloat or partially submerged and until finally locked to its supporting piling, should be stable under all weather conditions without dependence upon lines or other temporary means for holding it upright.

In place of ballast pumps it is practicable to use compressed air piped separately to each compartment as a means of controlling the contained water. Compressed air on the interior of the hull may also be utilized to offset in part the outside water pressure.

Perhaps the most serious punishment to which a rig of this type can be subjected is its use in shallow water in heavy weather. In this case the submerged pontoons would be close to the water surface and thus subject to heavy wave impacts. On the other hand, in shallow water, the size of the green waves is less than in deep water and the surfaces of the pontoon and supporting structure are shaped to minimize the pounding of the waves. As the depth of water and the corresponding submergence of the pontoons increase, the effect of the surface waves on the submerged structure is less and the supporting columns are sufficiently separated to offer a fairly free passage for rolling waves. Any structure of this type will be moored head to the worst prevailing seas and in the fore-and-aft directions the shipshaped pontoons are especially well prepared to take the impacts of the sea.

The horizontal wave thrust is of course taken by the vertical piles. When the rig is in shallow water where the wave impacts will be most severe the underside of the pontoons will be close to the bottom and the unsupported length of piles will be short. As the depth of water increases, the unsupported pile length will increase but at the same time the waves forces will diminish. As far as computations can be trusted an ample factor of safety under all conditions remains. Before constructing a rig of this sort, however, model tests including the effect of wave impact would doubtless be carried out.

The design provides ample storage for pipe, mud, water and fuel and hoisting facilities for transferring such stores from

barges to the drilling deck. On the basis of its complete equipment and easy transfer as a single unit from location to location and the use of buoyancy instead of piles for a major part of the support, it should be capable of drilling several wells a year.

The second combination of fixed and buoyant structures lies in the use of a pile-supported deck for the derrick, draw works and engines which must be rigidly supported, in conjunction with a water-borne element which carries the tanks, pumps and other equipment not requiring fixed support. This combination requires the safe all-weather mooring of the floating section and flexible connections between the fixed and floating parts. The movement of tanks and pumps in heavy weather and the flexible connections may be somewhat of an operating handicap and unless the unit principle of fabricating and transporting the fixed structure is employed, some of the possible cost economies will not be realized. An installation of this type is now under way and will be observed with interest.

Deep-water Platforms

The devices which have been mentioned are all considered as applicable to sea depths of 60 ft or less. The time may well arrive when drilling in still greater depths of water may be demanded. The types of platforms proposed for deep water will be as profuse and as varied as the inventive outpourings now are in the shallower areas.

Costs will unquestionably go up with sea depth but the basic principle of shore fabrication and erection in large self-contained units will prevail. Fig 3 shows a possible type of deep-water structure. The details have not been worked out but certain interesting principles are incorporated in it. It is assumed, for example, that some sort of closed bottom caissons jetted into the bottom may, at least in some locations, take the place of piles. The flotation elements will be kept as small as possible with compressed air used to reduce hydrostatic heads. The use of mechanically interlocked floats raised and lowered in vertical guides may be more practicable in furnishing stability during submergence than lofty wing towers would be. A device of this sort would lend itself to use in depths of over 100 ft.

In the preceding comments on offshore rigs, both present and future, no attempt has been made to cover the numerous types under construction nor the flood of ideas disclosed by issuing patents. We are here more concerned with a few of the principles inherent in the building, placing and removal of drilling platforms than in devices dealing with the actual drilling with which we profess no familiarity.

Oil Storage

The method to be used in providing oil storage in the vicinity of offshore wells will doubtless be given consideration. From this distance it seems probable that conventional oil tanks with the necessary separators and other devices will be placed on pile-supported structures, singly or in batteries, in the vicinity of an offshore well or field. This is another installation in which the use of prefabricated platforms is clearly indicated. The platform will require rigid cross bracing with the deck at an elevation to prevent the bombardment of the tank by sea waves. The tank elevation will also be great enough so that the contained oil can be flowed into transfer barges or tankers by gravity.

The conditions may occasionally prevail where the use of floating oil barges securely moored to the drilling platform or submerged oil tanks may be utilized. One possible type of floating oil tank is one having a bottom open to the sea. The tank itself contains enough built-in buoyancy for its flotation when filled with sea water but as oil is introduced through the top of the tank the sea water is gradually displaced until the tank is completely filled with oil. A tank of this type by virtue of its almost

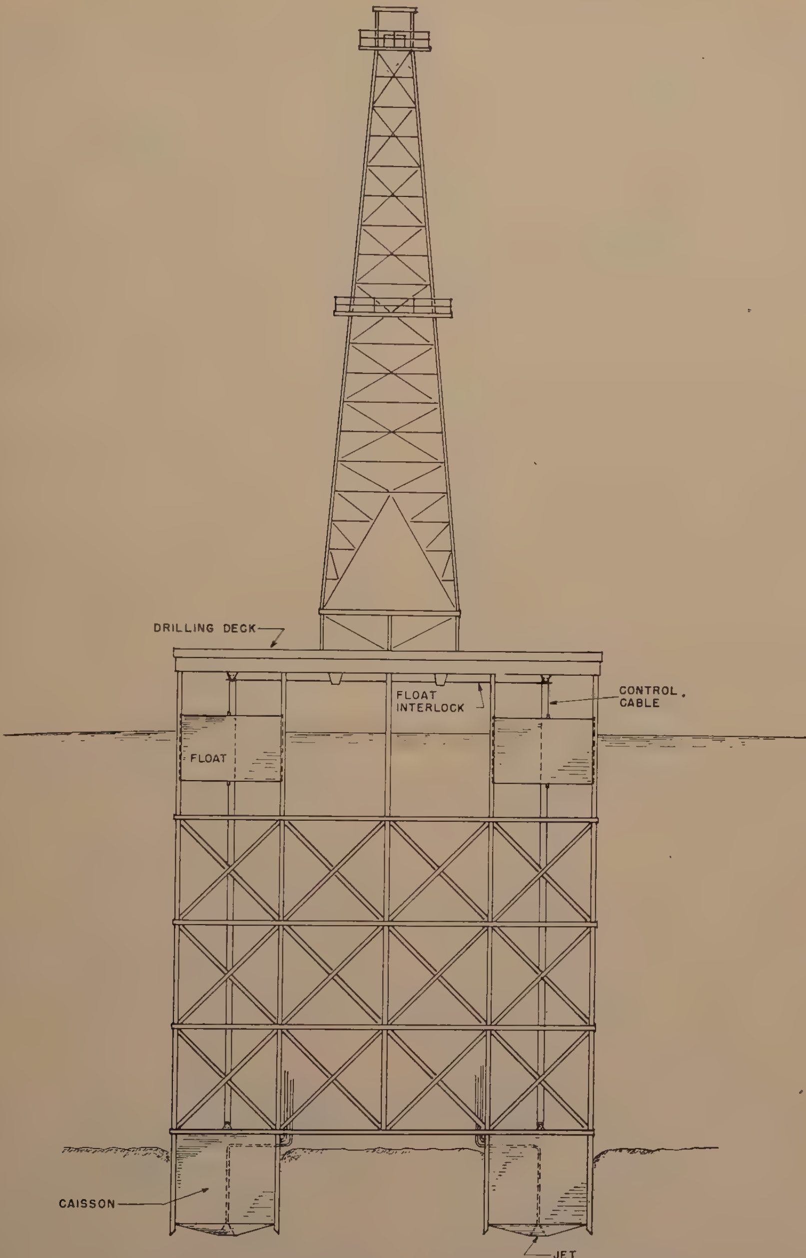

FIG 3—SCHEMATIC DRAWING OF A DEEP-WATER STRUCTURE.

complete submergence might be a possibility in deep water although its secure mooring and the necessity of pumping oil into a transfer vessel would both to some extent offset whatever other advantages it might offer.

Many improvements in recent years have been made in remote-reading liquid depth gauges. The use of such devices will enable the oil level in isolated tanks to be indicated at the filling point or elsewhere.

Other Angles

In connection with pile-supported structures in the Gulf areas under consideration, it should be noted that much of the bottom is comprised of relatively soft silts and clays. Under such conditions the bearing to be expected of piles will be obtained largely through surface friction rather than from point bearing. In the prefabricated structure previously referred to, pile penetrations of 75 and 80 ft are reported. The investment in a seagoing drilling platform is so great that in every case it is hoped borings and test piles will be driven at the site before the platform is placed in position. The economy and safety gained by obtaining such advance information is obvious.

In many instances, the heaviest seas come from a certain sector while other sectors will seldom, if ever, receive the full effect of storm waves. The direction in which the structure is placed will to a large extent be governed by this condition and there is a possibility that protective measures may be taken for reducing wave impact on the probable storm fronts.

In some cases, particularly in shallow water, a pile-constructed wave breaker might be effective in breaking up the storm waves before striking the drilling platform. The use of oil for calming waves at sea is well-known but the effect of oil is largely to quiet the breaking crests without materially reducing the size of the basic wave. There will also be objections to the use of oil in any quantity near the seacoast. Compressed air has often been suggested as a means for reducing the size and violence of sea waves. Several installations have been made and favorable reports published. There is an almost complete lack of scientific information on the use of compressed air, however, and the size and cost of compressor equipment will be important considerations to be settled before this type of installation can be considered. Constructive engineering experimentation on protective devices seems worthy of serious attention.

We mention quite casually the towing and mooring of these unwieldy floating objects. World War II brought out substantial improvements in towing gear and towing practices. Floating dry docks many times the size of the drilling rigs here discussed were towed as a matter of routine in all seasons to the far corners of the globe. With the help of wind tunnels and model basins, mooring practices were likewise explored and rationalized.

Whatever type of offshore structure is used, there will be the matter of Federal and State permits and lighting as an obstruction to navigation. It is to be hoped that the matter of jurisdiction up to at least 50 miles offshore will be settled on a workable basis. The encroachment on fishing grounds and other privileged areas will also be heard from in some localities.

Conclusion

The more one studies the offshore-drilling problem the more one is impressed with the necessity of eliminating all possible field construction where days and weeks of stormy weather may stop all activity and where work at best is hazardous. Drilling and oil-storage platforms not only require installation but removal and thus the field work is doubled.

The solution, therefore, is to arrive as soon as practicable at standardized types

of structure and to transfer all possible work of preparation and subassembly to land or to a sheltered harbor. The same line of reasoning urges the increase in size of the subassemblies with the ultimate goal of putting together the complete rig in one seagoing unit and in installing all possible equipment and deck houses before embarking for the offshore site. There is nothing in the size and weight of such a drilling structure as now visualized to prevent it from being transported in one piece from shore to sea location and moved from well to well. Novel lifting devices will be required but the special equipment can be used over and over again.

Planning a Multiple Well Directional Drilling Program for Offshore Locations

By John G. Jackson,* Member AIME and J. B. Murdoch, Jr.*

(Tulsa and Los Angeles Meetings, October 1947)

Abstract

The many mechanical, geological, and economic factors which influence the planning of a directional drilling program are thoroughly discussed and analyzed. It is demonstrated that the planning of a directionally drilled multiple-well artificial island location is a complicated undertaking and that it is imperative that complete planning and engineering analysis be undertaken before the program is started. Complete planning is profitable because all of the factors influencing the directional work are in general interrelated and many time compromises have to be made before a harmonious program results.

The engineering control necessary to accomplish a complicated directional drilling program is outlined. Various means by which engineering control can be increased, such as cylinder drilling specifications, are given. A hypothetical example is developed for a complete offshore artificial island of ten wells to demonstrate the more important factors involved in the planning. Included with this example are special charts and tables which make more rapid the drafting of directional drilling proposals and maps.

Introduction

A petroleum engineer must consider many and varied factors when planning a long range directional drilling program for an offshore or inaccessible location on an oil structure. The basic principles of directional drilling planning and operation must be reconciled with his company's drilling practices, and frequently special concessions to standard drilling and production practices should be made. The field techniques and tools used in directional drilling are well known and widely used, but the deliberate, careful planning of a complete directional program is in the main a recent innovation. This development, plus the increased demand for oil resources and the consequent exploitation of inaccessible structures and offshore locations, has placed this problem before many engineering departments for the first time.

Directional drilling programs of a very complex and difficult nature have been successfully carried out in the Mid-Continent and Pacific Coast regions. The planning itself of a directional drilling project, however, has not had the careful analysis it deserves and we can reasonably expect widespread future progress along these lines. Data and experience gained in these programs by the directional drilling service companies and the oil producers have been studied with the objective of giving the engineer a better conception of the factors which govern the various steps in planning a series of directional wells. The newest engineering procedures are the result of recent careful analysis of years of directional drilling work accomplished under the supervision of directional drilling service companies working with the oil companies.

The purpose of this paper is to illustrate

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the mechanics in planning a complete directional program on an oil structure where the productive limits are known. This will be done by means of an example of procedure. Before giving the example, a number of factors will be listed and discussed which would affect the particular problem so that the engineer will have a better conception of the steps involved in working up a logical plan. The authors are aware that other ways of directional drilling planning exist and wish only to submit this as a typical example for a particular project and not as an attempt to cover the general field of directional drilling applications.

Geological Factors Affecting Directional Programs

The choice of a suitable proposal for a series of directionally drilled wells is affected by the geological conditions found in the area where the work is to be carried out. From the economic viewpoint the engineer must have an idea of the productivity of the formation which is to be penetrated by the directed well. For instance, the rate of production in a slant hole sometimes is larger than in a straight hole because of the greater area of oil sand exposed. Well-spacing laws and regulations controlling bottom-hole spacing may also interfere with what may be an ideal program. If the engineer does not have data which can be used on such problems as that of expected production rates he is at a disadvantage in trying to estimate costs and the economics of the program.

Directional wells must be planned to take advantage of multiple zone completions, possible further deepening to lower zones, or the further perforating of a higher oil horizon. Under the last three conditions spacing is one of the most important factors and the proposal should be drawn so that each well can be used to the maximum benefit. Ordinarily the directional wells in a program are not all drilled at the same angle, so that unless the proper type of well proposal is chosen, the spacing is correct for only one zone. This factor is frequently over-looked and has resulted in the drilling of extra wells which careful planning would have made unnecessary.

The location of the artificial island so that the wells may be most advantageously drilled is influenced by the type and depth of the oil structure. The starting point of the wells should be located so that when they reach the productive zone the drift angle will be the proper one at which to penetrate the oil sands. Dip of the formation and the type of the oil structure also have a definite relationship to the proper drift angle of the well. A change in the drift angle or direction of the well will many times radically affect gas-oil ratios, rate of production, ultimate production, and so on. When geological conditions are such that a directional well must penetrate a number of oil zones all lying close to a salt dome, the proposal can be drawn so that the well will penetrate the zones parallel to the side of the salt dome. This can be accomplished by allowing the well to become vertical before entering the first zone or by directing the well's course in a plane parallel to the side of the salt dome. This last system permits the penetration of many oil horizons at points equi-distant from the face of the salt dome without the necessity of changing the drift in the directed well. This same problem arises in drilling highly faulted zones and is successfully solved in the same manner. The dip and strike of the formation, as well as its physical properties affect the drilling of the directional well. Under ordinary circumstances the wells which are drilled in a direction normal to the strike will be the easiest to control, while those which are parallel to the strike will cause the greatest difficulty.

In exploring a probable oil structure with the bit, a directionally drilled hole can be used to advantage. A high angled hole which has been drilled to the supposed productive horizon and which has failed to

encounter oil sand may be plugged back to a shallower depth. From this plug the well is redrilled straight to explore nearer the surface location. On one deep, high angled well, three separate bottom-hole locations were explored by successively plugging and straightening the well; thus the upper hole served for three test wells resulting in a considerable saving to the drilling company.

Selection of Maximum Drift Angle and Starting Point

The proper point from which to start the deflection of a directional well depends upon the formation characteristics, the average drift angle selected, and the rate of increasing this drift angle. The rate of increasing drift angle and the maximum drift angle are governed also by the total vertical depth to the oil sand and the horizontal deflection desired. These factors vary considerably with each field development; however, the engineer can follow certain basic considerations in his planning.

In general, the well proposal should be laid out so that the build-up rate and drift angle will be feasible. An average figure for the rate of building drift which is used in many instances is $2\frac{1}{2}°$ to $3°$ per 100 ft of hole drilled. There will be cases, however, where a high drift angle has to be obtained quickly, and many directional drilling programs have called for an increase in the drift angle of as much as $6°$ to $8°$ per 100 ft until a maximum drift angle of from $60°$ to $80°$ from the vertical has been achieved. The measured depth of such a high angle well of this type will rarely be greater than 8000 ft. In all cases where conditions permit, however, the best practice is to increase the angle slowly and drill a little more directional hole to get to the objective.

The average drift angle of the directional portion of the well is an important economic consideration in planning. Too low a drift angle or unnecessarily high angles are not recommended. Drift angles of $15°$ to $45°$ are successfully maintained for thousands of feet, and it is in this range that the most economical directional drilling is accomplished. Very low angles definitely increase the cost because of the greater amount of directional hole which has to be drilled and the difficulty of controlling a low angle hole while drilling. Very high angle wells also present special difficulties in logging, surveying and running casing.

The point or depth at which the deflection work is started will materially affect the directional program and the overall cost of the job. By the use of a reasonably high angle in the directed portion of the well, the directional work can be started deeper and more straight hole may first be drilled. When this is possible it will generally result in saving in rig time and other costs. Also, when the well is on production the possibilities of mechanical difficulties are less when the directional portion of the bore is near the bottom.

The problem of surface spacing and clearance of wells is related to the starting point and is discussed in the next section. The starting point, the depth, the desired deflection and the average drift angle which are chosen all bear a definite relationship to one another which must be analyzed.

The formations which are to be drilled should be studied, and the rate of penetration determined, so that the best zone in which to do directional drilling work may be selected. The well should definitely be planned so that directional drilling tools will in all probability not have to be set in unsuitable zones.

Well Spacing and Clearances

Theoretically it is possible to drill a large number of wells from one site; practical considerations, however, materially reduce this theoretical number. The spacing of wells on an artificial structure must be made with due consideration to the difficulties which may arise during the drilling period and the productive life of the well. In high pressure fields, very close spacing

could, in case of a blowout or fire, unnecessarily endanger a great number of wells. Also, space should be left for future pumping and servicing operations after the wells stop flowing. Fig 1, illustrates a typical well-spacing plan on a pier head in the Pacific Ocean where the wells are being pumped. Fig 2 is an aerial view of a pier construction.

FIG 1—PUMPING EQUIPMENT INSTALLATIONS SHOWING SURFACE SPACING IN A 7-WELL DIRECTIONAL PROGRAM ON A PACIFIC COAST PIER LOCATION.

There has been a great deal of experimentation on the problem of surface spacing and the following discussion is based upon a study of many types of spacing plans. Each directional program may call for a special spacing and arranging plan governed by factors characteristic of the production and drilling conditions.

There are two very distinct types of island plans for directionally drilled wells. The first and easiest plan to lay out pertains to an island where the wells radiate as do the spokes in a wheel. In this type the wells progress away from each other and the danger of interference between wells is at a minimum. The most common type, however, is the one in which all of the wells are drilled in substantially the same direction away from the unitized location. This type of island has to be planned very carefully in order that the greatest number of wells can be drilled without undue interference. Difficulties in the drilling operation are certain to occur unless the wells are laid out and drilled in a logical and systematic manner.

There are two general ways in which directional wells may be drilled so that interference is kept at a minimum. The first is to start the directional operations at different depths so that the wells will be separated shortly after they leave the island area. The second system is to have the wells build up to their maximum drift at different rates. The more distant wells would, under this last scheme, have the highest rate of increase in drift. In the case of high angle drilling in very congested areas both methods can be used concurrently in order to obtain sufficient clearances between wells.

Experience has shown that when directional work is started at very shallow depths of from 300 to 1000 ft, the surface locations may be made as close together as from 2 to 6 ft. When directional work is started at greater depths, the locations at the surface must be further apart. This precaution is taken because in any survey the cumulative error is somewhat proportional to the length and number of stations. Some programs have called for wells passing each other as close as 3 ft at depths of a thousand feet or more, but this practice is hazardous and should be avoided if possible. If, however, a well has to pass near to another well, the proposal should be plotted so that the well passes under the one already drilled. Wells should never pass closely over other wells because of the danger of the pipe cutting downward into the casing of the producing well.

The relationship of the surface spacing, the bottom-hole spacing and well clearance must be taken into account when laying out a multi-well program. The vertical distance between wells which are deflected at high angles will in most cases be less than the horizontal projection of the bottom-hole spacing in the oil zone. The bottom-hole spacing is generally measured in a plane which is at the mid-point of the production zone.

FIG 2—AERIAL VIEW OF PIER CONSTRUCTION FROM WHICH A DIRECTIONAL DRILLING PROGRAM HAS BEEN COMPLETED SUCCESSFULLY.
A close-up of one of the pier-head locations is illustrated in Fig 1.

These relationships are illustrated in Fig 3, a sectional view, which also shows the increase in penetration of the oil zone by the use of slant wells. The bottom-hole spacing is given as 660 ft and the distance between the well bores in this example is only 225 ft. The thickness of the oil zone is 200 ft but because of the angle and direction of the wells the penetration has been increased to 585 ft.

Engineering Control and Well Proposals

A directionally drilled well is not a "crooked" hole but is a directed well wherein all bends are controlled to stay

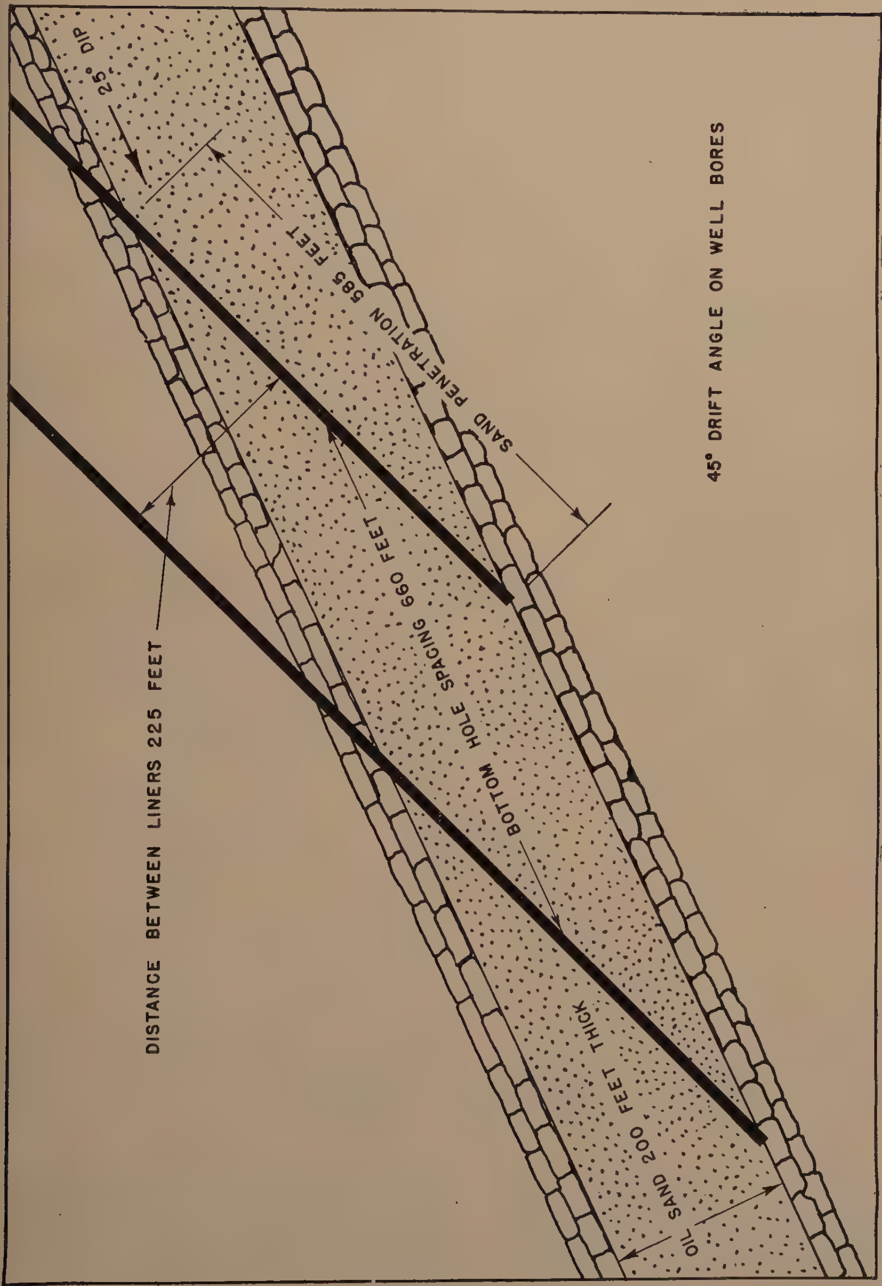


FIG 3—SECTION SHOWING BOTTOM-HOLE SPACING IN OIL SANDS OF TWO HIGH ANGLED WELLS.
Well spacing is on mid-point of sand thickness.

within known safe limits. The most frequent causes of mechanical trouble in slant wells are excessive dog legs and unnecessary wandering of the course of the well. A

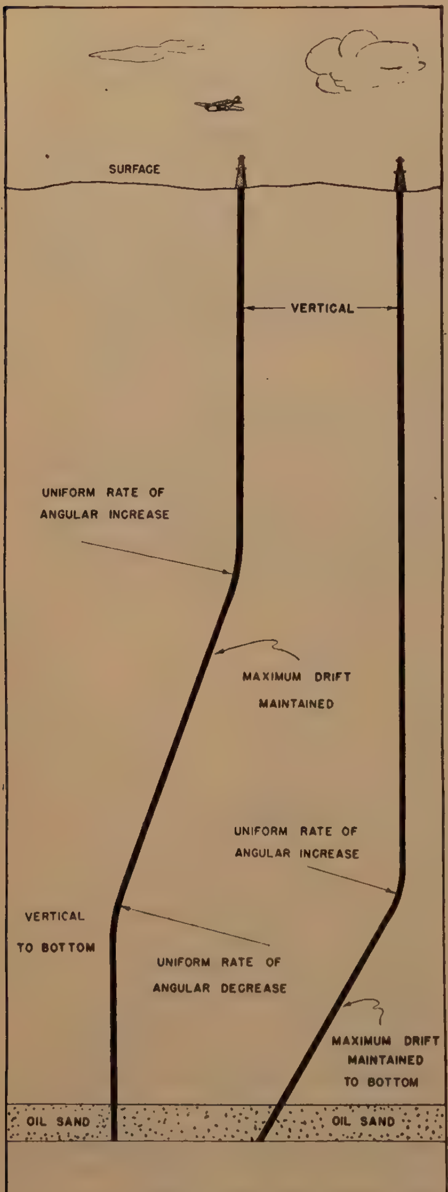


Fig 4—Section illustrating two general types of directional wells.

"dog leg" is the term applied to a change in the course of a well. It may be either a change in drift or a change in direction or a combination of both. The amount or size of the dog leg can best be calculated graphically and is generally expressed in degrees as a total dog leg in a certain specific length of well bore.

By the use of new and improved deflection tools excessive dog legs or changes in the course of the well can be minimized. In general each formation will have its own particular tendency toward keyseating if the dog leg exceeds a certain maximum amount. Other factors such as time, drilling procedure, depth, and the mechanical condition of the well also contribute to the tendency of the formation to keyseat. In general, however, the controlling factors are the weight on the drill pipe which provides the force, the radius of curvature of the well, and the type of formation. Since it would not be practical to determine the maximum permissible dog leg for each formation, a safe maximum angle is chosen which will fit the requirements for efficient drilling and the requirements for later production practices.

The recommended practice, now widely used, is to limit the maximum increase in drift to 2°30′ to 3°00′ per 100 ft drilled and to limit the maximum dog legs caused by deflection tools to 3° in any 50-ft section and 5° in any 100-ft section of well bore. The overall proposal will be on a basis of a 2°30′ increase in drift per 100 ft drilled, and the directional driller will attempt to stay as close as possible to the outlined proposal. An example is shown in Fig 10.

Directional wells are of two general types. In one the drift angle is increased at a uniform rate to the desired maximum deflection angle which is maintained until the oil zone is reached; in the second type the angle is increased at a uniform rate and maintained until the desired deflection is obtained at which point the well is brought back to vertical. Thus it passes vertically through the oil zone. These two types are illustrated in Fig 4. The first method is the simplest and is the most widely used. The

second system is used in situations where deeper horizons are to be explored or where directional drilling operations are difficult at the deeper depths.

A directional drilling proposal is drawn thus judge exactly when to run a deflection tool and still stay within the maximum dog leg which might be allowed. This all leads to a smoother and more regular directional well.

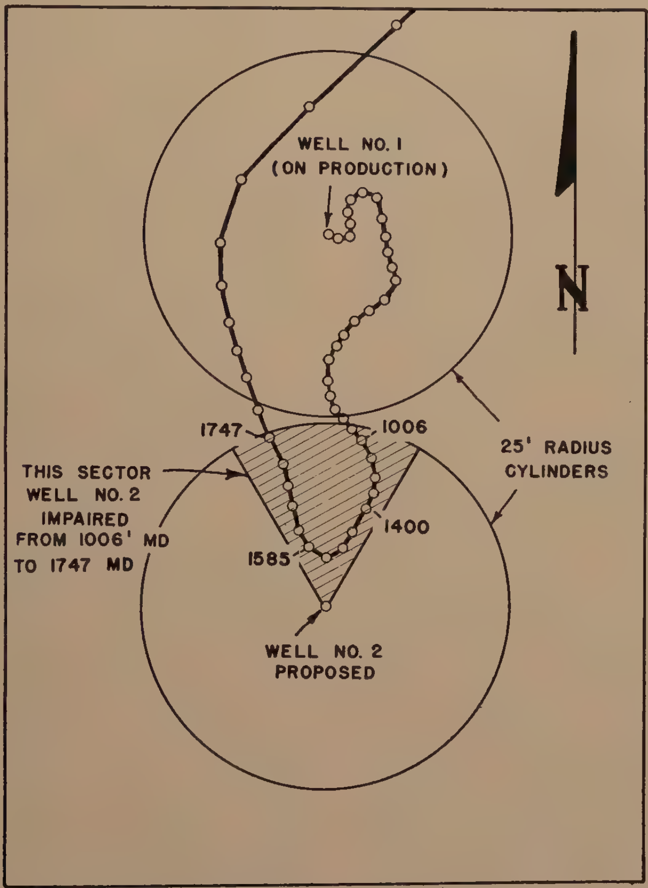


FIG 5—PLAN OF CYLINDER OF PROPOSED WELL SHOWING AN IMPAIRED SECTOR CAUSED BY INTERFERENCE FROM A PRODUCING WELL.

so that it illustrates both the course of the well and the cylindrical limits within which the well must be drilled. An important benefit to be derived from the use of cylinder drilling is that it guarantees a better well mechanically and definitely places a control on the quality of the field work. The field engineer can project the course of the well ahead of the drill and can

The regular 100-ft cylinder can be further "zoned" or restricted for special reasons. Another well may be too close, or the engineer's opinion may be that the well should be "lined out" to penetrate a difficult zone, or perhaps geological considerations require greater exactness. An example of a zoned cylinder is shown in Fig 5. The section of the cylinder shows a type of

zoning required to prevent wells from passing too close to each other and the reduced portion near the surface is necessary because of close spacing. The section of the cylinder gives a very true picture of the actual dog leg, or bend, and also shows exactly where the bore hole is located in the cylinder at any particular depth.

Cylinder drilling has been the major factor in the recent improvements in directional drilling procedures. The overall picture shows that it has given the engineering control necessary to drill better wells at a lower cost and with greater efficiency.

Directional drilling companies which have been in this type of work for years have the facilities and personnel enabling them to be of assistance to a company which does not have sufficient data on hand.

Directional Tools

The planning of a directional program would not be complete unless consideration were given to the use of the proper deflecting tools and allied equipment necessary to complete the job. The program should be developed in a manner so that the most effective tools and equipment available can be used on the directional work. The drilling equipment should be rigged with the necessary sand line, and so on, so that fast means of surveying can be used. If the drift angle given in the proposal is low, non-magnetic drill collars might save rig time. High drift angles can be successfully surveyed with "trigger" bits and retractable equipment.

Full gauge deflection tools should be run if the formation and hole size permit in order that valuable rig time can be saved. The use of the knuckle joint or the whipstock can be based upon such factors as hole size, depth, and formation. In order to achieve smooth changes of angle and to be able to maintain the course of the well the proper types of reamers and drill collars must be used. The best results are gained by using spiral roller-type reamers which provide good stabilization and a uniform contact with the wall of the well bore.

Casing Program

The casing program which is chosen for a directional well generally will vary slightly from that which would be chosen for a straight hole. The bending stresses which are set up in the casing by the curvature of the hole are small enough to be disregarded, it is good practice, however, to increase the thickness of the casing through the curved portion of the well bore to resist wear from the drill pipe. Many operators also follow the practice of running one grade better casing on directional holes than they would have used on a comparable straight hole. On very deep and long directional jobs or when difficult directional drilling conditions are encountered, the casing program may be altered so that a protective string can be set to safeguard the upper portion of the hole.

Casing will, in the majority of cases, run as easily in a controlled drilled hole as in a straight hole and modern directional drilling practice does not call for reduction in casing size for a given size hole. In fact, the constant use of wall reamers in directional drilling procedures keeps the well bore in good condition and many operators have now found that the reaming operations which are ordinarily done prior to running casing can be eliminated. Cementing through perforations is not considered good practice in high angle, directionally drilled wells unless the cement points are first block under-reamed to permit better distribution of the cement. In all high angle wells stiff spring stabilizers should be used on and near the shoe joint to centralize the casing in the well bore and prevent the cement from channeling.

Typical Example

The following example illustrates one solution to the problem of planning a

multiple well, directional drilling program for offshore locations with the geological, mechanical, well-spacing, and marine-structure conditions given. Although it undoubtedly is not the only possible manner in which the planning can be done, it is a practical solution. It allows for the use of the data previously discussed. Assumed conditions are as follows:

Geological—

Oil structure is nearly horizontal. There is not enough dip to affect well spacing.

Oil structure considered to be sufficiently productive to warrant economic production on one well to 40-acre spacing.

Top of oil sand is at 8500 ft vertical depth. Thickness of productive zone is 250 ft; therefore, terminal depth is 8750 ft vertical depth approximately. There is no evidence of an oil zone below this depth.

Formation to be penetrated: unconsolidated; surface to approximately 500 ft; balance is sand, shale, and sandy shale with numerous hard shells at points between 1400 and 1625-ft depths. Lime formation occurs from 6850 to 7250 ft vertical depth (400 ft thick). Rock bits must be used in the latter stratum.

Mechanical—

Casing program: 13⅜-in. casing, 0 to 800 ft vertical depth
7-in. casing, 800 to 8500 ft vertical depth
5-in. liner in oil zone

Hole sizes to be 17-in. from 0 to 800 ft vertical depth
10⅝-in. from 800 ft to terminal depth

Drilling equipment is adequate to penetrate to depth specified. In conjunction with 4½ in. full hole drill pipe, directional drilling surveying-type bits and non-magnetic drill collars are to be used.

Wells to be drilled are expected to flow. It is contemplated that oil produced will be pumped to storage on mainland through submarine lines.

Well Spacing—

Spacing will be 26 ft center-to-center of casing heads of completed wells.

Island structure can be situated so that courses of directional wells will radiate from marine structure without necessity of crossing each other.

Marine Structure—

Structure is located in the open sea about 2 miles offshore where the depth of water is 20 ft at low tide. Tidal range is about 8 ft.

The drilling island is presumed to be a steel sheet-pile structure (cofferdam) tied across with steel tie rods. Earth fill is made inside the sheet-piling with a bearing-pile mat structure of sufficient strength to support oil derricks. Erosion at the base of the structure is minimized with heavy stone rip-rap. Structure will be rectangular in shape with 72 by 150 ft top surface. This will accommodate 10 wells on spacing previously specified.

Power generating units, pipe racks, mud pits, bunk houses, and so on, will be installed on barges moored alongside the island.

Directional Drilling—

Increase of drift is to be not over 2°30′ per 100 ft drilled. Maximum dog leg will not exceed 2°30′ in 50 ft or 5° in 100 ft.

The type of well chosen will be one which increases in drift at a uniform rate to the maximum and maintains this angle to bottom. Although it is anticipated that wells should flow in their early life, when pumping is necessary, fluid pump and sucker rods will be in alignment. By penetrating oil zone at the maximum drift angle more productive sand will be exposed. This type of well is being chosen since no productive upper sands are known to exist. If, in the future, a productive sand is discovered at a greater depth than 8500 to 8750 ft

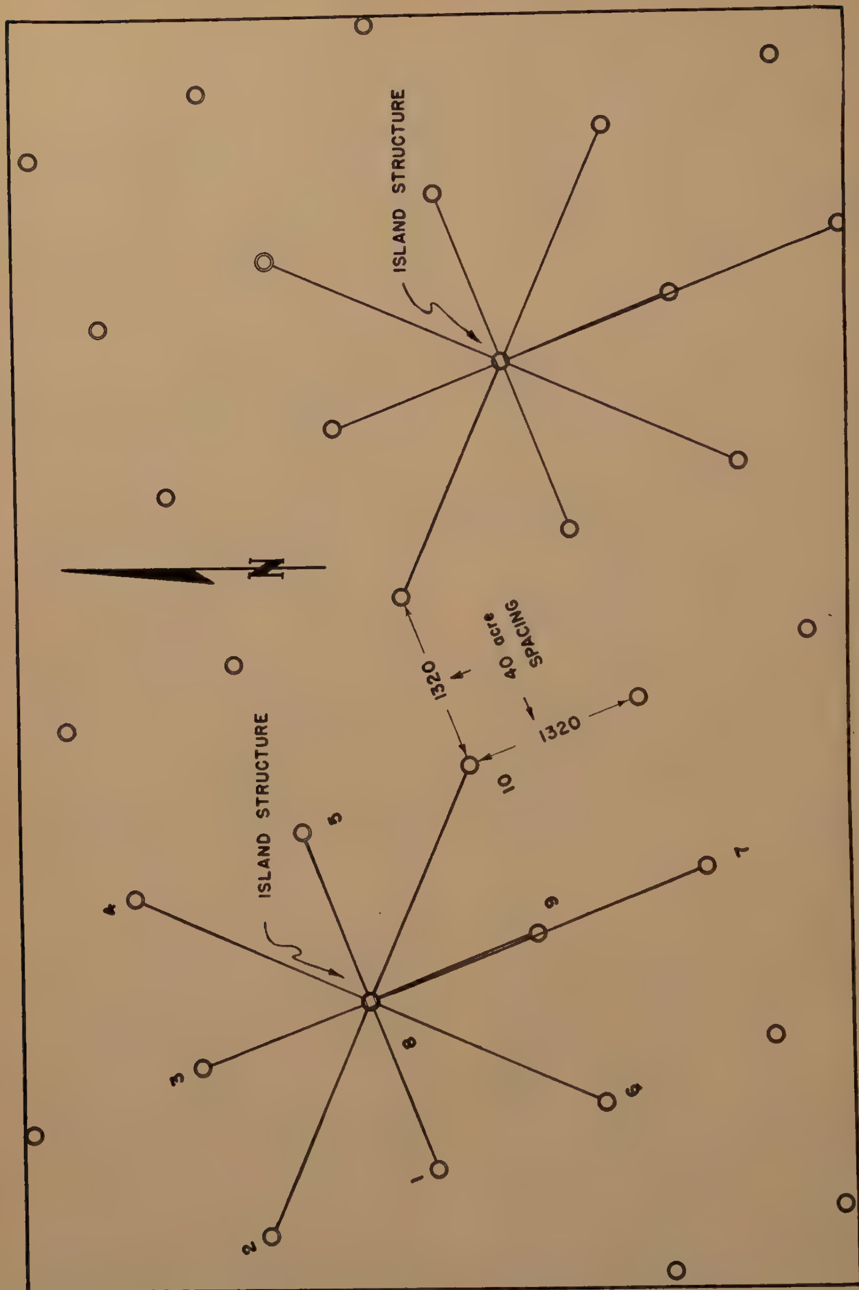


FIG 6—PLAN OF MARINE STRUCTURE SHOWING DIRECTIONAL WELLS RADIATING TO BOTTOM LOCATIONS.

vertical depth, it may be produced on similar well spacing by pulling the liners and redrilling the wells. This can be accomplished by straightening them at a uniform spacing); the site of the marine structure is chosen so that one well in the group may be drilled straight (Fig 6, Well No. 8).

Since the geological formation is prac-

FIG 7—DETAIL OF ISLAND SHOWING SURFACE LOCATIONS OF NINE PROPOSED DIRECTIONAL WELLS.

rate of decrease in drift. The water string is sufficiently large to permit the drilling of 5⅝ in. hole if the wells are redrilled. A considerable saving of drilling time is effected on this type of well since the maximum angle is maintained to bottom, thus eliminating the necessity of slower drilling while the well is being straightened at bottom.

Solution of Example

The proposed bottom locations of the wells are laid out on 1320-ft centers (40-acre tically horizontal, bottom locations are selected which separate the horizontal courses of the wells as much as possible (Fig 7). The true bearing and distance from the surface location to bottom of each well is next scaled or computed. The middle point of the thickness of the oil zone (8625 ft vertical depth) is used as the bottom of the well when the well spacing is planned.

It has been proved through experience in directionally drilled wells that the maintaining of drift angles of less than 15° makes accurate control of the well course

very difficult. Hence the maximum angles of all wells should be greater than 15°.

Bearing in mind that the weight of drill pipe (and sucker rods when the well is pumped), as well as the rate of increase in drift per 100 ft drilled below the deflection point, have a direct bearing on the tendency of the drill pipe to keyseat (or the sucker rods to wear tubing) the amount of straight hole made before deflecting the well should be as great as possible. Economically this is advantageous since the straight hole is normally cheaper to drill.

Limiting the last two considerations mentioned above is the fact that it would be preferable to drill a straight hole through the shells between 1400 and 1625 ft and the lime stratum between 6850 and 7250 ft, or to have the drift increased to maximum before either of these depths is reached. Either solution would eliminate the necessity for doing deflection work in formations not ideal for the setting of deflection tools.

Proposal for Well No. 7

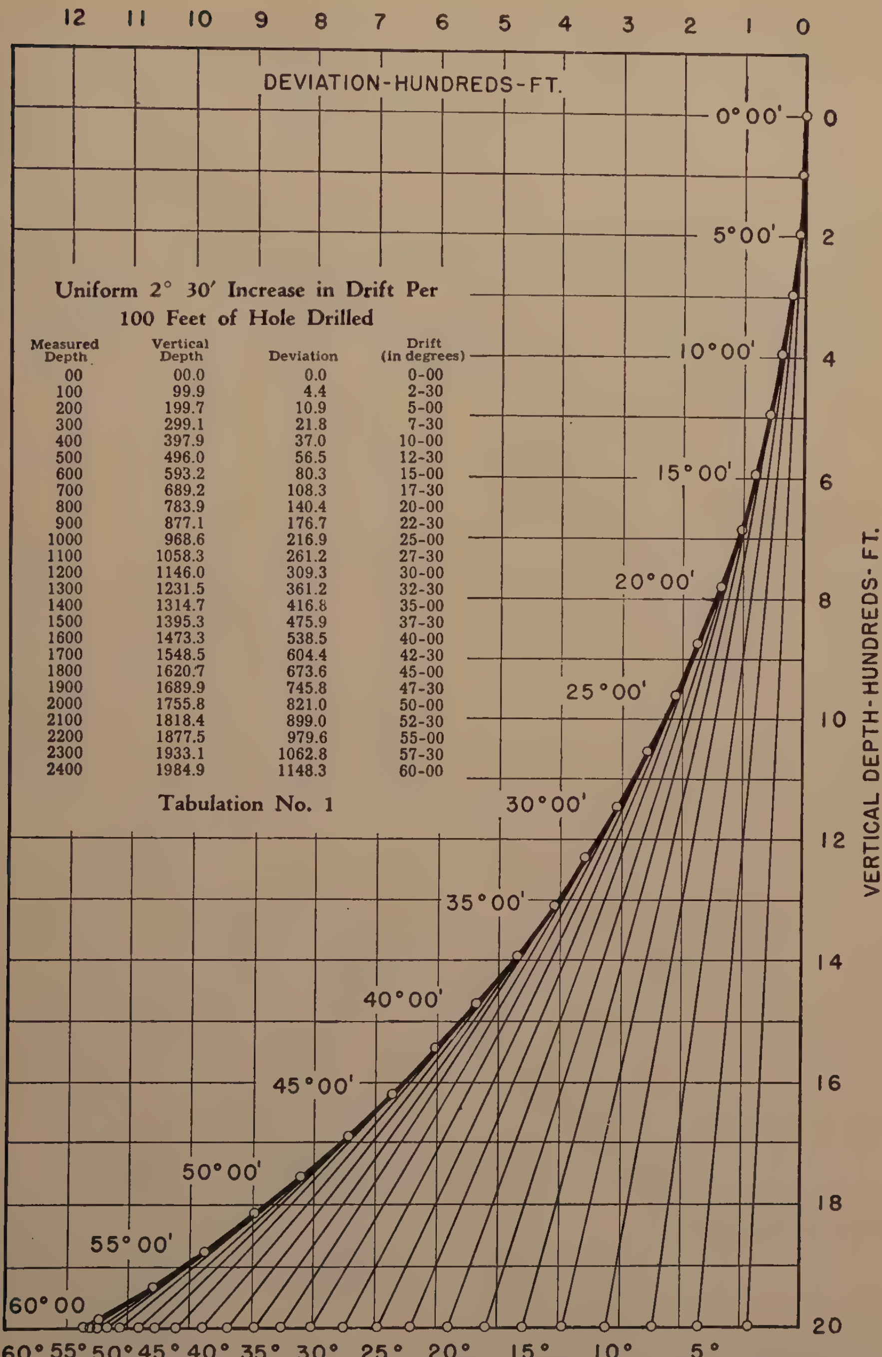
Since each of the nine directional wells (No. 8 is straight) has a different deflection distance to reach its proposed bottom location, each well must be considered separately. In this example then, a complete directional drilling plan will be perfected for No. 7 well which requires the greatest deflection. The course of this well is S 20°45′ E and the distance to the ideally spaced bottom at 8625 ft vertical depth (center of the thickness of the oil sand) is just 2640 ft.[a] It will be noted that the direct course of No. 7 well comes very close to the planned course of Well No. 9. Any possibility of the holes coming in close proximity to each other except in their vertical portions can be eliminated by starting deflection at different depths. Obviously it would be most convenient to start deflecting Well No. 7 at a shallower depth than No. 9 since the former well must travel a greater distance.

To ascertain a rough approximation of the minimum deflection angle necessary, the deviation distance (2640 ft) is divided by the total vertical depth of the well (8625 ft). The natural tangent obtained (0.3061) would be for approximately 17° drift. Thus it is shown that the well will necessarily be above the minimum of 15° decided upon. With this amount of deflection necessary, the well must pass through the lime stratum at 6850 to 7250 ft at the maximum drift since it obviously would be impossible to deflect the well 2640 ft in 1375 ft of vertical depth. However, it would be advantageous to start deflecting the well below the unconsolidated surface formations and, if possible, deeper than the zone of shells from 1400 to 1625-ft depth.

To progress toward a more definite determination of the starting point for deflection, 2000 ft is taken as a round figure which is safely below the bottom of the zone of shells at 1625-ft depth. By dividing the deflection distance of 2640 ft by the balance of the vertical depth (6625 ft), 0.3985 or the natural tangent of 21°45′ drift is obtained as an answer. Since this angle is nearest to 22°30′, which appears in the estimating chart mentioned below, the latter figure (22°30′) will be considered to be the necessary maximum deflection angle.

By inspection of Fig 8, it is ascertained that 900 ft of measured depth will be required to increase the drift from 0°00′ to 22°30′ at a rate of 2°30′ increase per 100 ft of drilled hole. From Tabulation No. 1 (Fig 8) it is noted that the deflection distance at the 900-ft measured depth point is 176.7 ft and the corresponding vertical depth is 877.1 ft. See also Fig 9. If 176.7 ft is subtracted from the total deflection of 2640 ft, the remainder obtained in 2463.3 ft. This last amount of deviation is to be attained with an average drift angle of 22°30′. Hence, 2463.3 ft is divided by the tangent of 22°30′. The result, 5974.1 ft, is

[a] It is considered that the vertical depth has been adjusted for the elevation of the top of the rotary table above sea level.



Uniform 2° 30′ Increase in Drift Per 100 Feet of Hole Drilled

Measured Depth	Vertical Depth	Deviation	Drift (in degrees)
00	00.0	0.0	0-00
100	99.9	4.4	2-30
200	199.7	10.9	5-00
300	299.1	21.8	7-30
400	397.9	37.0	10-00
500	496.0	56.5	12-30
600	593.2	80.3	15-00
700	689.2	108.3	17-30
800	783.9	140.4	20-00
900	877.1	176.7	22-30
1000	968.6	216.9	25-00
1100	1058.3	261.2	27-30
1200	1146.0	309.3	30-00
1300	1231.5	361.2	32-30
1400	1314.7	416.8	35-00
1500	1395.3	475.9	37-30
1600	1473.3	538.5	40-00
1700	1548.5	604.4	42-30
1800	1620.7	673.6	45-00
1900	1689.9	745.8	47-30
2000	1755.8	821.0	50-00
2100	1818.4	899.0	52-30
2200	1877.5	979.6	55-00
2300	1933.1	1062.8	57-30
2400	1984.9	1148.3	60-00

Tabulation No. 1

FIG 8—GRAPHIC CHART FOR ESTIMATING ANGLES OF DIRECTIONALLY DRILLED WELLS.

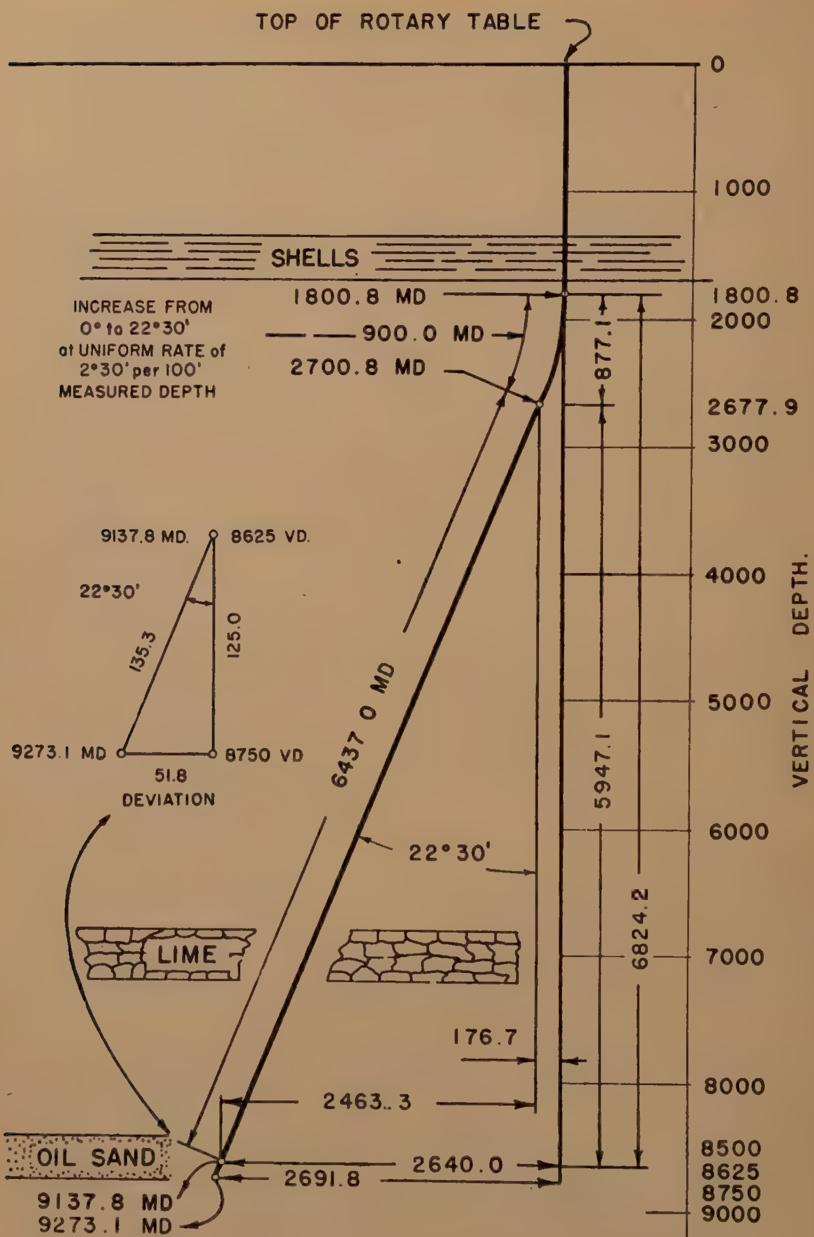


Fig 9—Section to accompany computations on Well No. 7.

the vertical depth necessary to attain the deviation of 2463.3 ft. The sum of 5947.1 and 877.1 ft is 6824.2 ft. This is the vertical distance consumed by the deflected hole from the point at which the deflection is started. The result of subtracting 6824.2 ft from the total vertical depth of the well (8625 ft), is 1800.8 ft vertical depth. This figure represents the depth at which deflection is to be started. (Vertical depth and measured depth are identical at this point since the upper hole is considered to be vertical.)

Having established the theoretical point at which to start deflecting the well, the vertical depth of the point at which the well will attain the maximum deflection is found by adding 877.1 ft to the deflection starting point. This sum is 2677.9 ft vertical depth. The measured depth of this point will be 900.0 ft plus 1800.8 ft or 2700.8 ft measured depth. By dividing the vertical distance during which the well averages 22°30′ drift (5947.1 ft) by the cosine of 22°30′ (0.9239) the measured depth for the corresponding portion of the well is found to be 6437.0 ft measured depth. Adding this figure to 2700.8 ft gives 9137.8 ft. This is the measured depth corresponding to 8625 ft vertical depth.

There remains the deviation and measured depth to be computed from 8625 ft vertical depth (center point of the thickness of the oil zone) to 8750 ft vertical depth (the bottom of the oil sand). The angle (22°30′) and the vertical depth (125.0 ft) of this small triangle are given. By use of the tangent and cosine the measured depth of 135.3 ft and deviation of 51.8 ft are computed. These figures are added to the appropriate measured depth and deviation figures for 8625 ft vertical depth. Thus the measured depth is 9273.1 ft and the deviation is 2691.8 ft at the terminal depth of 8750 ft vertical depth.[a]

[a] Although the thickness of the oil sand is but 250 ft, by penetrating it at a 22°30′ drift, 270.6 ft of sand is exposed. This represents a gain in exposed productive sand of approximately 8.3 pct. The percentage increase in exposed sand in a directional well in comparison to a straight hole naturally is much greater as the angle of the well is increased.

The results of the calculations may be tabulated as follows:

Measured Depth, Ft	Vertical Depth, Ft	Deviation, Ft	Remarks
1,800.8	1,800.8	0.0	Point at which deflection is started.
2,700.8	2,677.9	176.7	Point at which drift (by uniform rate of increase from 0°00′ to 22°30′ at uniform rate of 2°30′ per 100 ft drilled) has attained the desired maximum.
9,137.8	8,625.0	2,640.0	Point at which well will arrive at center of thickness of oil zone.
9,273.1	8,750.0	2,691.8	Point at which well will intersect bottom of oil sand.

Drafting the Proposal Drawing

With the above information at hand a directional drilling proposal is drafted. A directional drilling proposal includes a plan view, a vertical section of the proposed well made in the plane of the well course, and a section across the cylinder in which the well is to be drilled. This proposal is drafted on cross-section paper or cloth in order that it may be reproduced and especially so that the survey of the well may be plotted upon it as the well is drilled. The directional drilling engineers will use a copy continuously during the time in which the well is being drilled. They habitually plot the course of the well on all three sections in order to formulate their future control plans. Such a proposal for Well No. 7 is illustrated in Fig 10. A cylinder has been described about the proposed course of the well on both the plan and vertical section. The cylinder has a 25-ft radius from the surface to the start of deflection (1800.8 ft measured depth). At this point the radius increases to 50 ft, and the cylinder is this size to 9000 feet measured depth. There it starts to taper to a 25-ft radius cylinder at

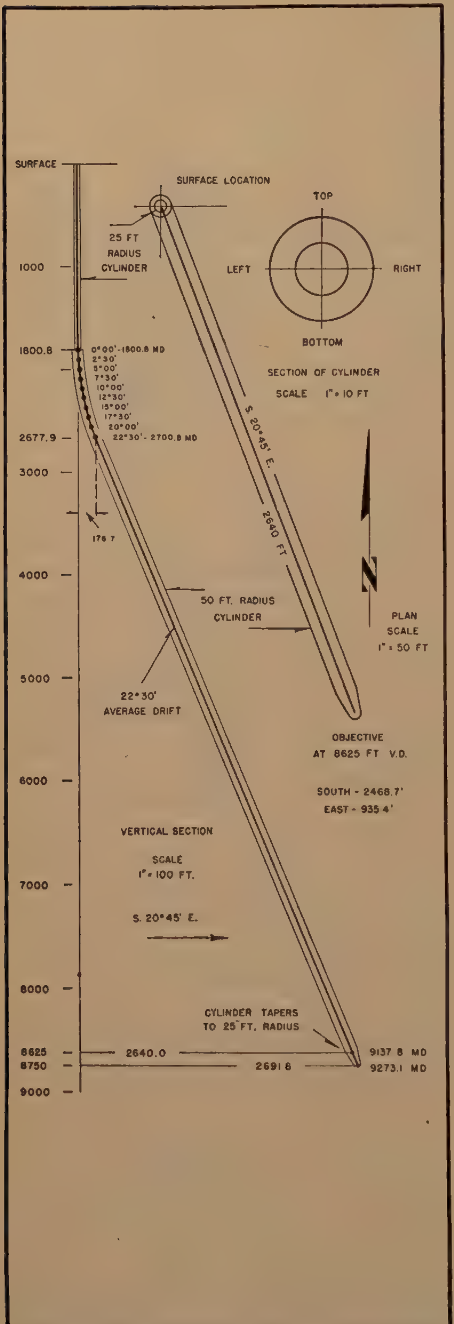


Fig 10—Directional drilling proposal for Well No. 7.

the terminal depth. The radius of the cylinder is small where the well is straight. The well spacing of 26 ft permits no larger cylinder for this and the adjoining wells from the surface to the deflection point. After deflection has been started the well can be allowed more latitude, hence the 50-ft radius cylinder. Since it is desired to keep the well spacing as accurate as possible in the oil sand, the cylinder is gradually tapered from 50 to 25-ft radius, reaching the minimum at the terminal depth. A typical section across the cylinder is shown on the proposal in order that the exact location of the well may be made in relation to the cylinder at that point.

Directional Drilling and Surveying Procedure in Accordance with Proposal

Assuming that the proposal illustrated for Well No. 7 shows no interference with the similar proposals made up on the remainder of the directional wells in the group to be drilled from the island, actual drilling can be commenced. For purposes of illustration it will be presumed that Well No. 7 is the next to be drilled after No. 8 (the straight well). Since the location of the well must be known at all times, it is essential that an accurate survey be maintained up-to-date as drilling progresses. This is achieved by running an open-hole type single shot on sand line, a regular or inside single shot down the drill pipe into a special non-magnetic drill collar, or by taking directional readings with a single shot run out through a trigger type or retractable coring-type bit. Drift and direction readings are taken at intervals of not over 100 ft so that an accurate survey may be obtained. It is essential that the survey readings be taken at short enough intervals to ensure a good survey. It should be borne in mind that the accuracy of well surveying varies inversely with the depth. Probably the greatest accuracy of magnetic surveys is no better than 3 ft in location per 1000

ft drilled. As the drift and depth increase the limits of error become greater. During the drilling of the straight portion of the well to the depth at which deflection is started, the survey readings are computed and the location of the well is plotted on both the plan and vertical section of the proposal. On the plan the location of the well is plotted by rectangular coordinates. In plotting on the section the plotted point on the plan is projected on the plane of the proposed course of the well. This distance is scaled from the surface location. Used in conjunction with the vertical depth the well position is plotted on the vertical section. The vertical hole to shallow depths can be drilled within a 25-ft radius cylinder by careful drilling methods and observation of the best straight hole drilling practices.

Drilling and Surveying Procedure in Accordance with Proposal—Deflected Hole

After completion of the hole to 1800-ft depth, the directional drilling engineers are put in charge of the well in so far as the directional drilling aspects are concerned. The appropriate type of deflecting tool will be oriented into the hole at this point, faced to increase the drift of the well in the proposed direction (S 20°45′ E). The directional drilling crew takes sufficient single-shot pictures to be sure of the location of the well at all times. They recommend drilling setups, (types of bits, reamers, and drill collars) and their use in so far as speed of rotation and weight on the drilling bit, pump pressures, and the like, are concerned. All of these factors together with the type and bedding of formations encountered in drilling are of importance in directional drilling practice. They vary widely with different structures and localities. Normally the engineers plot the location of the well as the single-shot readings are taken. In their planning they use the section of the cylinder (see Fig 10) on the proposal. The distance, right or left, is scaled on the plan from the proposed well course to the actual course of the drilled well. This measurement is made normal to the proposed well course. In the same manner on the vertical section the distance the drilled well is above or below the proposed well course is ascertained. These distances are used as ordinate and abscissa in plotting the location of the well in the cylinder. The center of the circle is considered the proposed well course. The control engineer thus is able to check the placement of the well in the cylinder after each single-shot reading has been taken. The location of the well within the cylinder is the basis for their recommendations as to methods to be used in drilling. Aside from noting the effect of different drilling setups and methods which they recommend, the control men try to anticipate and provide for eventualities which might occur as the well is drilled deeper. Thus they set deflecting tools in such a manner that if an unexpectedly large dog leg is obtained from a deflecting tool it will be of benefit in the long range program. In a way it might be said that the successful directional drilling engineer is planning 300 to 400 ft ahead of the bit.

General Recommendations Covering the Drilling of all Wells from One Island

In drawing proposals for each of the directional wells of a group the inter-relation of the wells must be considered. The deflected portions of the wells can best be separated by commencing the deflections at different depths. In cylinder drilling if the same rate of increase in angle is used on all wells they will tend to stay separated although they may follow nearly parallel courses. The normal sequence for drilling wells is to drill the lower angled wells first. A major portion of the experience gained in drilling these wells will be of value when those maintaining higher drifts are attempted.

It is probable that numerous minor

changes will be made in the program as the individual wells are drilled. Hence it is wise to reconsider each proposal in light of the experience gained in the drilling of the preceding well. Often a well will encroach upon the cylinder of a well for which the proposal has been drawn but which has not as yet been drilled. In some cases where directional wells are numerous it is imperative that the course of a new hole come very near the casing of another well. When this condition arises the section of the cylinder is shown with a sector which must not be entered between certain depths during the drilling of the new well. Such a situation is illustrated in Fig 5 in which a sector of a cylinder is not to be entered by the new well between 1006 and 1747-ft depths.

It is advisable to employ similar surveying methods on all of a group of wells drilled in juxtaposition. For example, if the open-hole method of running a single shot is used, its use should be continued throughout the whole group of wells. Thus any inherent errors in the methods of using the surveying equipment will not affect the correlation of the wells.

Conclusion

It is the sincere hope of the authors that the above discussion and consideration of the factors involved in the planning of a multiple well directional drilling program for offshore locations will be of benefit to those engineers who may be called upon to plan programs of this type.

Acknowledgments

The authors wish to take this opportunity to express their appreciation to the Eastman Oil Well Survey Company for permission to prepare and present this paper; to Mr. D. S. Johnston of the Signal Oil and Gas Company for his critical review and suggestions; and to the helpful cooperation of the many oil men with whom actual directional drilling programs have been planned and carried out, thereby supplying the practical foundation of experience upon which this paper is based.

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Discussion

R. O. Pollard, Jr.*—The authors must be commended for presenting this practical approach to a problem that has become of such importance in development planning. They have, of a necessity, limited their discussion to generalizations of the many variables encountered in planning any specific program. I have noticed in setting up a directional drilling proposal, such as shown on Fig 10, the "Section of Cylinder" or the "Cylindrical Section," it is convenient to include the plotted course of any previously drilled hole that falls within or approaches the proposed cylinder and these additional courses to be plotted in convenient station distances relative to the measured depth of the proposed well.

Also, it has been the practice of many operators to restrict the cylinder at the shut-off point for the reason that the possibilities of additional tool settings and time spent opposite the producing interval is greatly reduced. Would it be possible to generalize the approximate number of tool settings expected, such as, to the relative number of tool settings per interval of measured depth between various ranges in drift? Cylinder drilling has many advantages, as the authors have pointed out. One advantage I believe they have failed to mention is that after the plan is approved, management has, in effect, turned over to operations its tolerances in a definite measurable unit and that is a factor that every engineer and operating man can well appreciate.

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Dan S. Johnston*—Mr. Jackson and Mr. Murdoch's paper presents a general analysis of the planning used in the construction of a multiple well directional drilling program. Such planning of directional drilling programs was initiated by various operators and service companies some 15 years ago. Today any large directional drilling development is fully dependent on complete and experienced planning.

Initial plans for a multiple well directional drilling program are based on the existence of an inaccessible oil pool whose limits and horizons are usually not completely determined. In the experience of some operators as many as 50 pct of the wells directed toward this pool will be searching for and attempting to define the limits and characteristics of the oil horizons in the pool. Therefore, an important consideration in the directional program is planning for the location of each oil horizon in the pool as soon as economically feasible. Possibly the first or second well should be planned as a deep test to locate the various oil horizons, unless economics or offset conditions dictate otherwise. Early location of oil horizons will allow more complete planning and will be especially valuable where surface drilling areas are limited

A second important consideration is the choice of the order of development of each oil horizon in the pool. Unless impractical because of competitive conditions in more shallow zones; or because of a fixed development expenditure or other economic reasons, the deepest oil horizon should be the first developed, followed successively by each shallower horizon. Total development costs should then be lower because:

1. Secondary objectives are economically available in shallower horizons. A secondary objective should be planned or allowed for in every directional hole for use in case the primary objective is unproductive.

2. Directional drilling through partially depleted upper zones will be minimized.

3. Primary deep drilling will provide abundant engineering and geological data in the shallower horizons allowing more accurate and economical planning.

4. Primary deep drilling will allow an earlier evaluation of the surface area needed for total development.

A third important consideration in planning is the usage of as much flexibility as possible in the directional control of each well. As noted in Mr. Jackson and Mr. Murdoch's paper, cylinder control is an important advancement in directional drilling. Usually the use of a 100-ft radius cylinder through the oil sand will meet the approval of petroleum engineers for efficient spacing and drainage where 10-acre or larger spacing is involved. The cost of a well can be increased in some cases 50 pct by restrictions to a small cylinder. In addition, an increased number of dog legs may be necessary to follow a small cylinder. In general, cylinders smaller than 50 ft in radius should not be resorted to except for special purposes such as clearance of other wells or dense well-spacing programs.

A fourth important consideration is the early evaluation of offsetting requirements. Competitive operators directionally drilling along a common boundary line should reach an early agreement as to the number and course of the offset wells. The establishment of equitable drainage at a boundary line is usually more difficult and complicated in directional operations than in straight hole operations.

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CHAPTER II. *Oil-shale Development*

Oil-shale Resources of Colorado, Utah and Wyoming

By CARL BELSER*

(Denver Meeting, September, 1947)

ABSTRACT

THIS paper summarizes the data on the oil-shale deposits of western Colorado, Utah and Wyoming. It is based on published reports by the U. S. Geological Survey, on the results of core drilling and sampling by the Bureau of Mines, on the drill cuttings from the General Petroleum well, on a recent unpublished report by the Geological Survey on the geology of Naval Oil-Shale Reserves No. 1 and No. 2, and from information supplied by geologists of private companies who have investigated the Green River formation. The paper also contains a revised estimate of the grade and tonnage of minable thicknesses of oil shale of western Colorado.

INTRODUCTION

The oil shales of the Green River formation of Colorado, Utah and Wyoming comprise an important natural resource for the production of synthetic liquid fuels. The oil shale in western Colorado generally is more amenable to exploitation, apparently richer, and probably more persistent than in Utah or Wyoming.

Work is now being done by the Bureau of Mines near Rifle, Colo. to ascertain the best procedures for mining the oil shale, producing shale oil from the oil shale, and converting the oil into more salable products. As a part of this program, holes were drilled and cores were taken of the oil shale on Naval Oil-Shale Reserve No. 1. In addition, drill cuttings were obtained from a well drilled through the Green River formation by the General Petroleum Co. about 18 miles northerly of the Naval Oil-Shale Reserve.

GEOLOGY

During middle Eocene time a broad, shallow body of water, now called Uinta Lake, covered northwestern Colorado and east-central Utah; a similar lake, known as Gosiute Lake, was in southwestern Wyoming. Each of these contemporary lakes was bounded by high hills; the drainage was to the south. The Green River formation was laid down as sediments in the bottoms of these lakes. It is 3000 ft thick and has been divided into the following four members:

Member	Thickness, Feet	Characteristics
Evacuation Creek.	1,000	Fine gray and brown sandstones, with interbedded gray marlstones and a few thin beds of oil shale.
Parachute Creek..	700 to 1,300	Black, brown, and gray marlstone, including the principal oil-shale units, a few thin altered tuff, analcite, and chert beds; sandstone tongues near base.
Garden Gulch....	630 to 720	Gray marlstone, with some gray and brown shale and a few thin oil-shale beds.
Douglas Creek....	430 to 470	Brown sandstone and gray shale, with a few thin oil-shale beds.

The Green River formation overlies

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conformably the 4000-ft Wasatch formation of the lower Eocene and in places is overlain by the Bridger formation of the middle and upper Eocene or by lava flows.

The Green River epoch has been estimated by Bradley[1] as lasting 5,000,000 to 8,000,000 years, deposition occurring at a rate of approximately 1 ft in 2000 years. Depending upon the periodic rainfall, the lakes ranged from fresh-water lakes to brackish marshes.

The Parachute member is the principal oil-shale member of the Green River formation; this member is considered in estimating the oil-shale resources contained in this paper.

Bradley[2] pointed out that organic material is most abundant in the center of the lake basins, diminishing in all directions toward the shore phases. A close study of presently available evidence indicates that the oil-shale zones in the center of the old lake basins are richer than at the margins of the basins. Most of the exposed sections sampled, with the possible exception of sampled sections taken in the Parachute Creek, Clear Creek, Southern Cathedral bluffs, and Rulison areas, probably are of lower grade than the oil shale nearer the center of the old lake basins.

In the Parachute Creek area the oil shale is divided into three zones: The main oil-shale zone, 460 to 630 ft thick; the middle oil-shale zone, 230 to 270 ft thick; and the lower oil-shale zone, 205 to 220 ft thick. These zones are generally separated by 50 to 150 ft of marlstone, which is nearly barren of oil. The middle and lower oil-shale zones are insignificant at the Bureau of Mines oil-shale mine, whereas north of Piceance Creek all three zones are continuous, forming an oil-shale zone 1300 ft thick.

In general, the oil shale is a magnesium marlstone which is rich in organic matter. The organic matter chiefly is remains of primitive aquatic plants and animals, the major part of which is a structureless amorphous material derived from the partial putrefaction of aquatic organisms that grew in the lakes. The marlstone is a tough, strong rock. The organic matter is called kerogen, which is vaporized upon the application of heat; the condensate is shale oil.

References are at the end of the paper.

Oil-shale Reserves

Published results of sampling the oil-shale measures are meager; only the results of 99 sampled vertical sections[1,3–7] of oil-shale beds are available, of which 25 are less than 70 ft long. Moreover, the oil content in the majority of the sampled sections was estimated and not assayed. The results in many cases were reported by number of feet of 15- to 30-gal shale. Of these sampled sections, 67 were taken in Colorado, 24 in Utah, and 8 in Wyoming. Most of the surface samples were good-grade shale taken from outcrops in steep cliffs.

Colorado

Colorado contains 2592 square miles of Green River formation, of which 630 square miles is covered by Bridger formation and 72 by igneous flows (see Fig 1). A section through the oil shales of Colorado is shown in Fig 2.

No sampled sections are available of the 430 square miles of Green River formation in Moffat County. Three sampled sections taken on Grand Mesa, about 30 miles east of Grand Junction, indicate that this area of 314 square miles was probably on the southern fringe of Uinta Lake and would contain no oil shale of economic value. Four sampled sections from Battlement Mesa, 15 miles southwest of Rifle, indicate this area of 85 square miles is too low grade to be considered in this estimate. No sampled sections are available of the small neck, containing 108 square miles of Green River formation, which connected the Piceance Creek Basin with the Uinta Basin of the old lake. Three sampled sec-

tions from the oil shale on Raven Ridge near the eastern fringe of the Uinta Basin indicate a poor quality of oil shale, the oil content increasing toward the center of the basin.

least 15 gal to the ton. His estimate included a loss of 40 pct of the oil shale in mining. He gave a revised estimate of 79,625,998,000 bbl of "Total Oil" in Colorado in beds not less than 1-ft thick

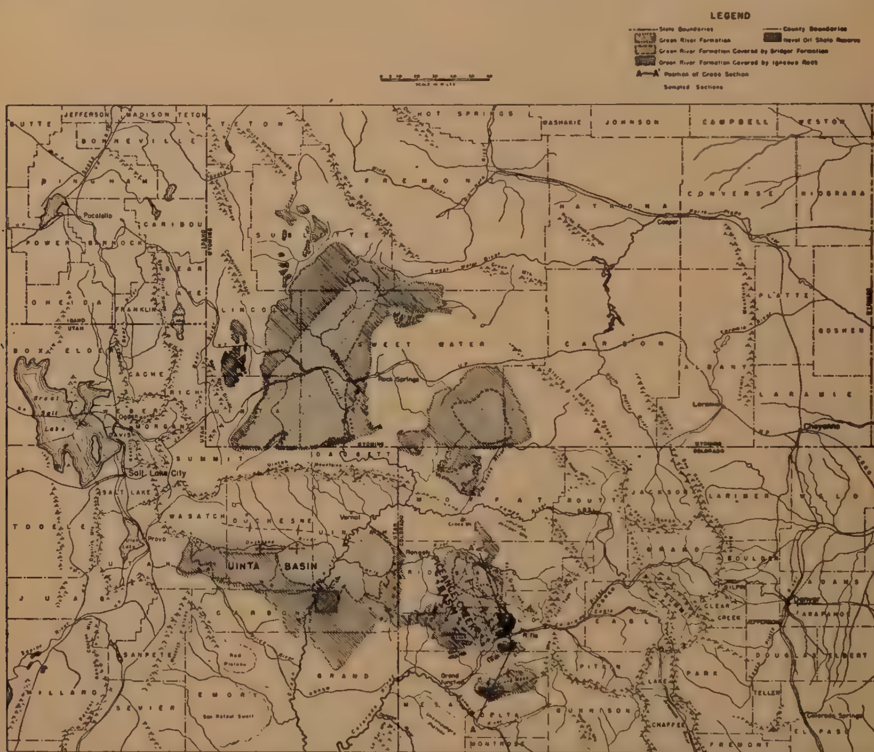

FIG 1—PRINCIPAL OIL-SHALE DEPOSITS IN COLORADO, UTAH AND WYOMING.

The Piceance Creek Basin contains 1655 square miles of Green River formation, and 57 sampled sections from this area are available (see Fig 3). Of these sections, 25 were taken from the fringe area of the basin, 8, although good, are short sections ranging from 31 to 73 ft in length and were not considered in making this estimate, and 24 were taken inside the fringe. The samples define an area of approximately 1000 square miles.

Winchester[8] estimated that the oil shales of northwestern Colorado contained 40,640,000,000 bbl of recoverable oil from beds 3 ft or more thick and yielding at yielding not less than 3000 bbl of oil per acre, in Appendix I—"The Oil Possibilities of the Oil Shale of the United States" of Report II of the Federal Oil Conservation Board to the President of the United States issued January 1928.

Duncan and Denson[9] estimated that in the area east of Parachute Creek, bounded on the north by the north line of T. 5 S., there are 77 square miles of oil shale averaging more than 25 gal a ton that contain 127,000,000 bbl of oil per square mile and 87 square miles of oil shale averaging better than 10 gal a ton that contain 495,000,000 bbl of oil per square mile. This

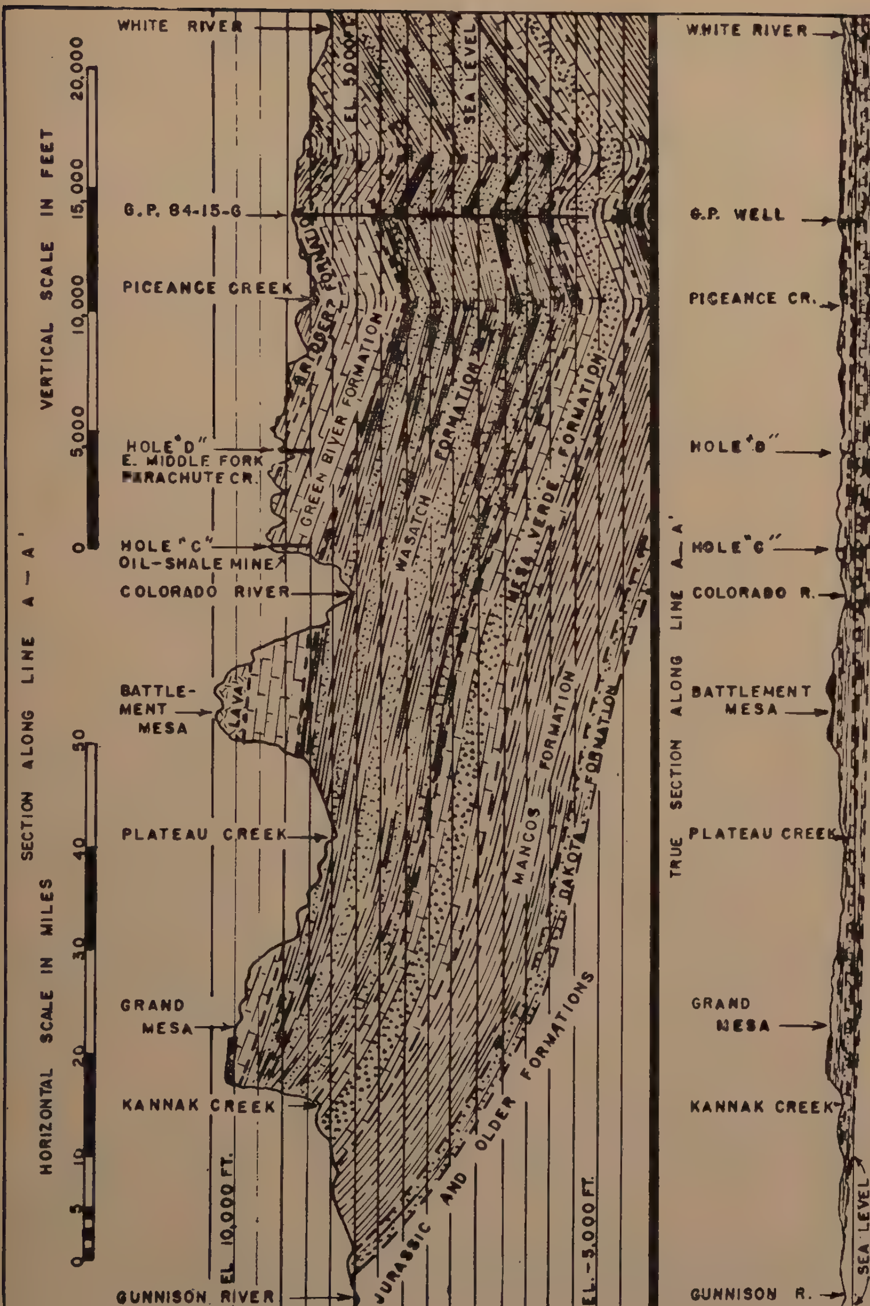

FIG 2—GEOLOGIC SECTION CONTAINING GREEN-RIVER FORMATION, WESTERN COLORADO.
Note: Location of Line A-A' shown on Fig 1.

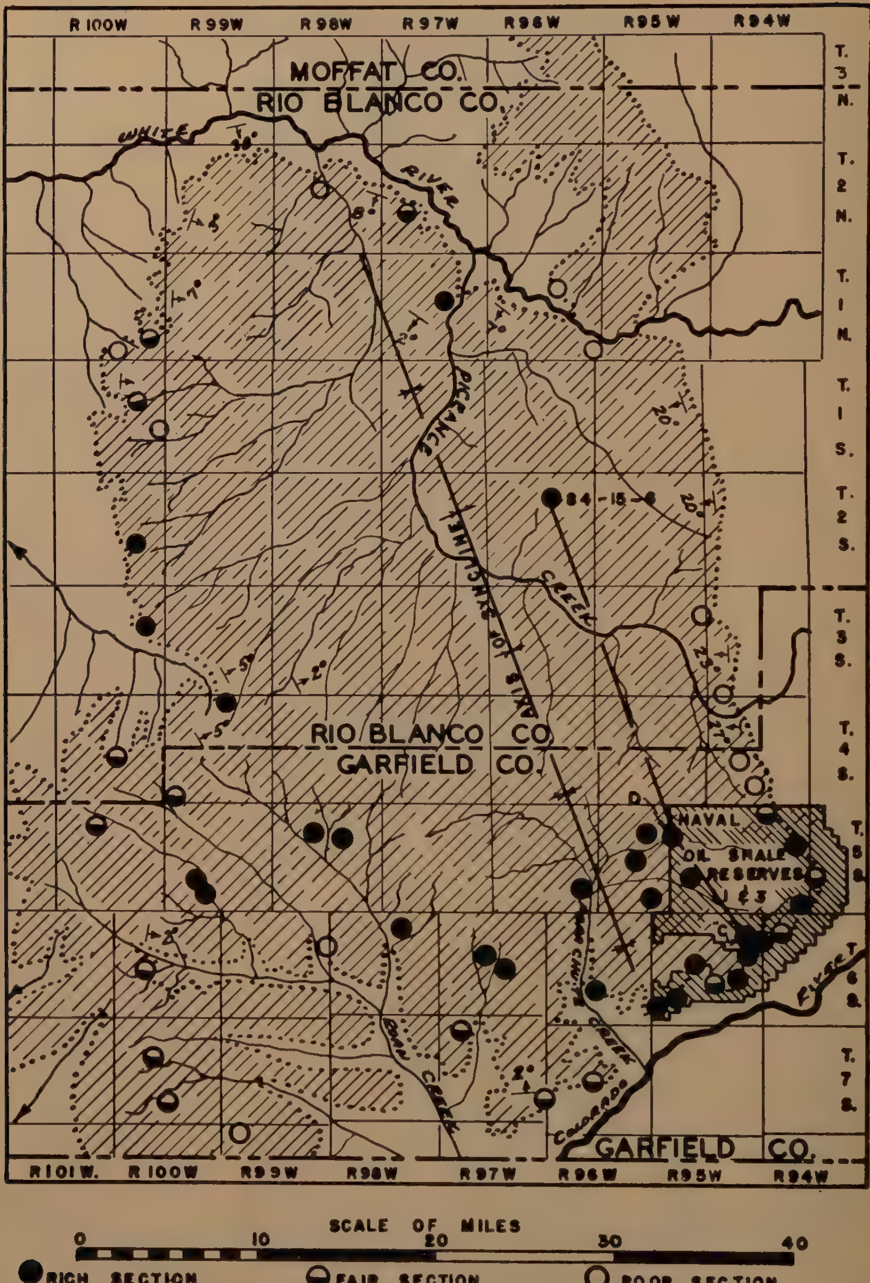

FIG 3—GREEN RIVER FORMATION IN PICEANCE CREEK BASIN.

figure included the Naval Oil-Shale Reserves Nos. 1 and 3. Their estimate per square mile for the richer shales west of the reserve and nearer the bottom of the basin syncline is 21 pct higher than for the shales in the reserve, and their estimate for the lower grade shales west of the reserve is 48 pct higher.

Drill Hole Sampling

The Bureau of Mines drilled three vertical diamond drill holes at the Bureau of Mines oil-shale mine site about 8 miles west of Rifle, Colo., in sec 12, T. 6 S., R. 94 W. The holes were drilled at the apexes of an equilateral triangle with sides 1779 ft long and were called *A*, *B* and *C*. A fourth hole, Hole *D*, was drilled in sec 11, T. 5 S., R. 95 W, 7 miles northwest of the mine site. The cores obtained were 2⅛ in. in diameter and are known as NX size. The recovery of core generally was excellent and was nearly 100 pct through the better grade of oil shale. The cores were sawed in half longitudinally and each one-foot of core through the richer sections was sent as a separate sample to the Bureau of Mines Petroleum and Oil-Shale Experiment Station, Laramie, Wyo., for assay. The drilling was done in 1945 and 1946 and, as far as known, the cores are the only ones ever taken from the Green River formation for oil-shale studies. Assay returns from these three holes, *A*, *B*, and *C*, check with underground sampling in the mine and indicate that the fresh unaltered shale contains about 15 pct more oil than corresponding sections in the weathered cliff exposures.

Samples for assay also were obtained from a well drilled by the General Petroleum Co. south of the White River, north and west of Piceance Creek. The well is called 84–15–G and is 20 miles northwesterly of Hole *D* in sec 10, T. 2 S., R. 96 W. The samples were the drill cuttings for each 10 ft of holes and therefore could not be as representative of the bed penetrated as the core samples from the diamond drill holes. The cuttings samples also were sent to Laramie for assay. The great thickness and good grade of the oil shale encountered in the oil well near the bottom of the Piceance Creek Basin changes a heretofore lightly-regarded area into one of high potentialities.

The graphic sections showing the yields of the oil-shale samples are shown on Fig 4. A revolved section through the drill holes *A*, *C*, and *D* is shown in Fig 5. A section through Holes *A*, *C*, *D*, and 84–15–G is shown on Fig 6.

Holes *A*, *B*, and *C* were drilled only one-third of a mile apart and the three logs are very much alike. Hole *C* revealed that the lower 74 ft of the top oil-shale measure, including the mahogany ledge, is able to yield 28.55 gal of shale oil per ton. Since 14.8 cu ft of oil shale of this grade weigh a ton, each square mile may yield 100,000,000 bbl of shale oil with no provision for oil shale lost in mining.

This same minable bed will yield 30.97 gal per ton over a thickness of 92 ft in *D* hole, seven miles northwesterly of Hole *C*. Applying the same calculations, a square mile may yield 128,000,000 bbl of shale oil. The average of Hole *C* and Hole *D* is 83 ft of 28.89 grade oil shale, or 110,000,000 bbl per square mile.

The drill cuttings samples obtained from Hole 84–15–G, 20 miles northwesterly of Hole *D* and 27 miles from Hole *C*, although not as reliable as the core samples, indicate that the same bed is 140 ft thick at a grade of 25.39 gal per ton at this place; the yield would be 159,000,000 bbl of shale oil per square mile.

Geologic evidence exists that the oil-shale measure is richest along the axis of Piceance Creek Basin. Holes *C*, *D*, and 84–15–G are not along this axis, therefore they may be considered representative of the area.

It is considered that the bed with the mahogany ledge of the grade, as shown in

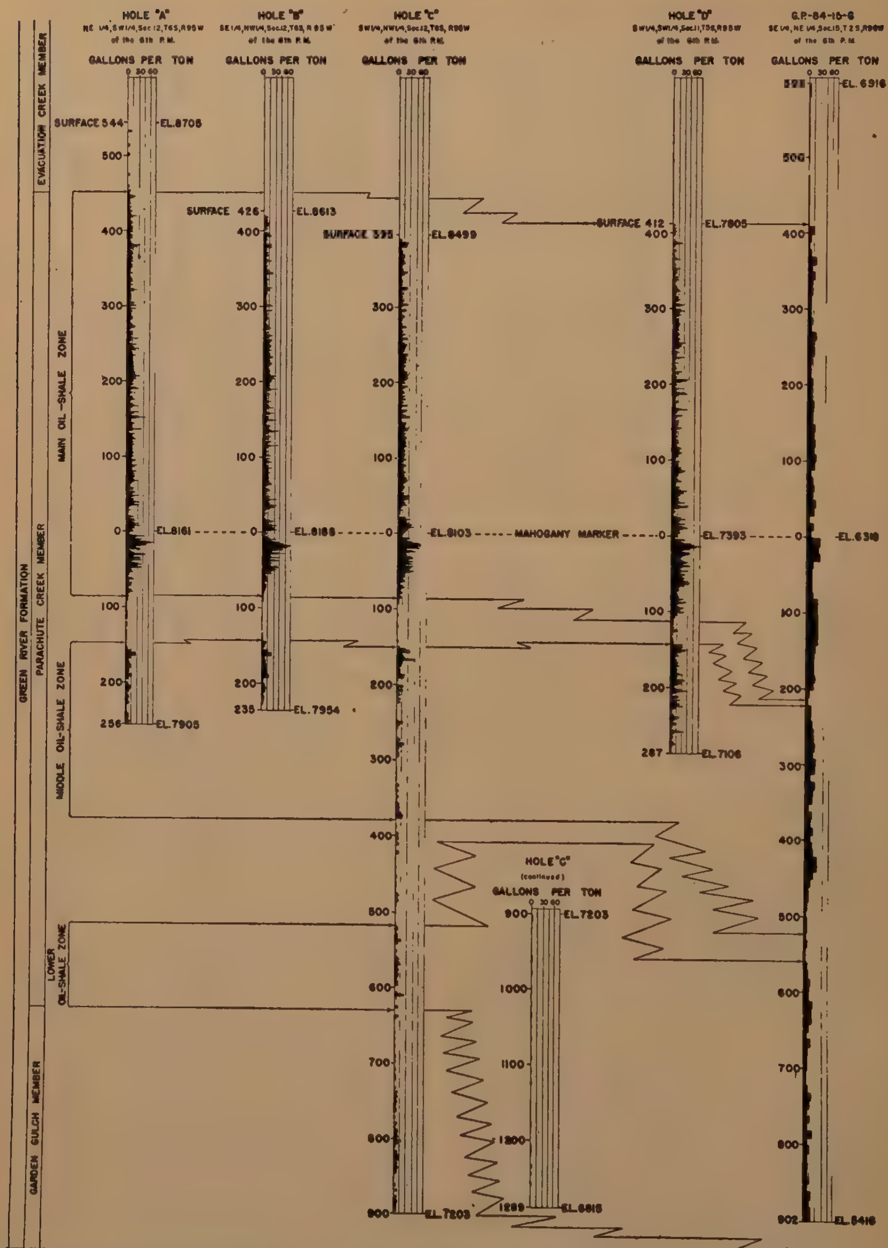

FIG 4—GRAPHIC SECTIONS SHOWING YIELDS OF OIL-SHALE BEDS ENCOUNTERED IN DRILL HOLES IN THE PICEANCE CREEK BASIN.

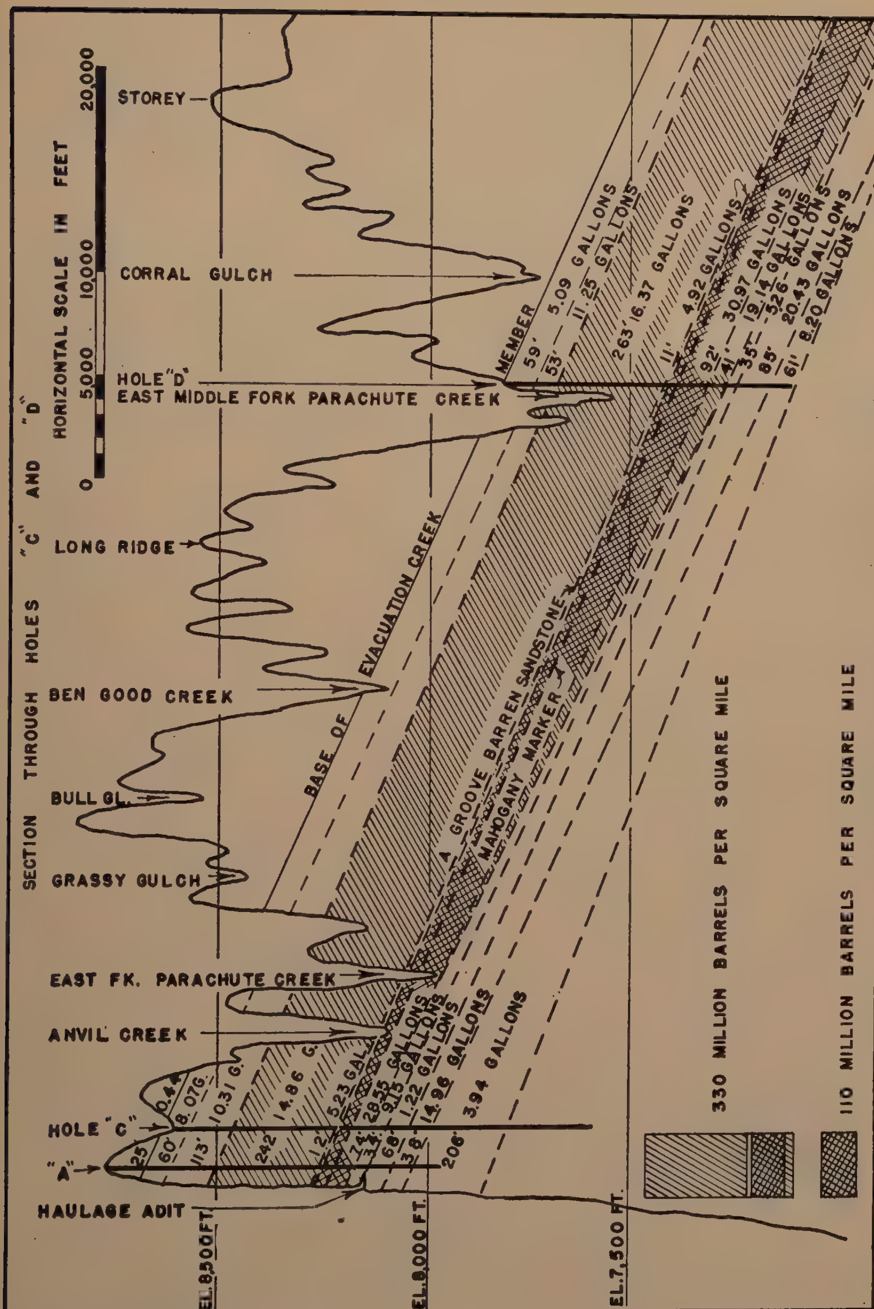

FIG 5—GEOLOGIC SECTION THROUGH DRILL HOLES NAVAL OIL-SHALE RESERVE NO. 1.

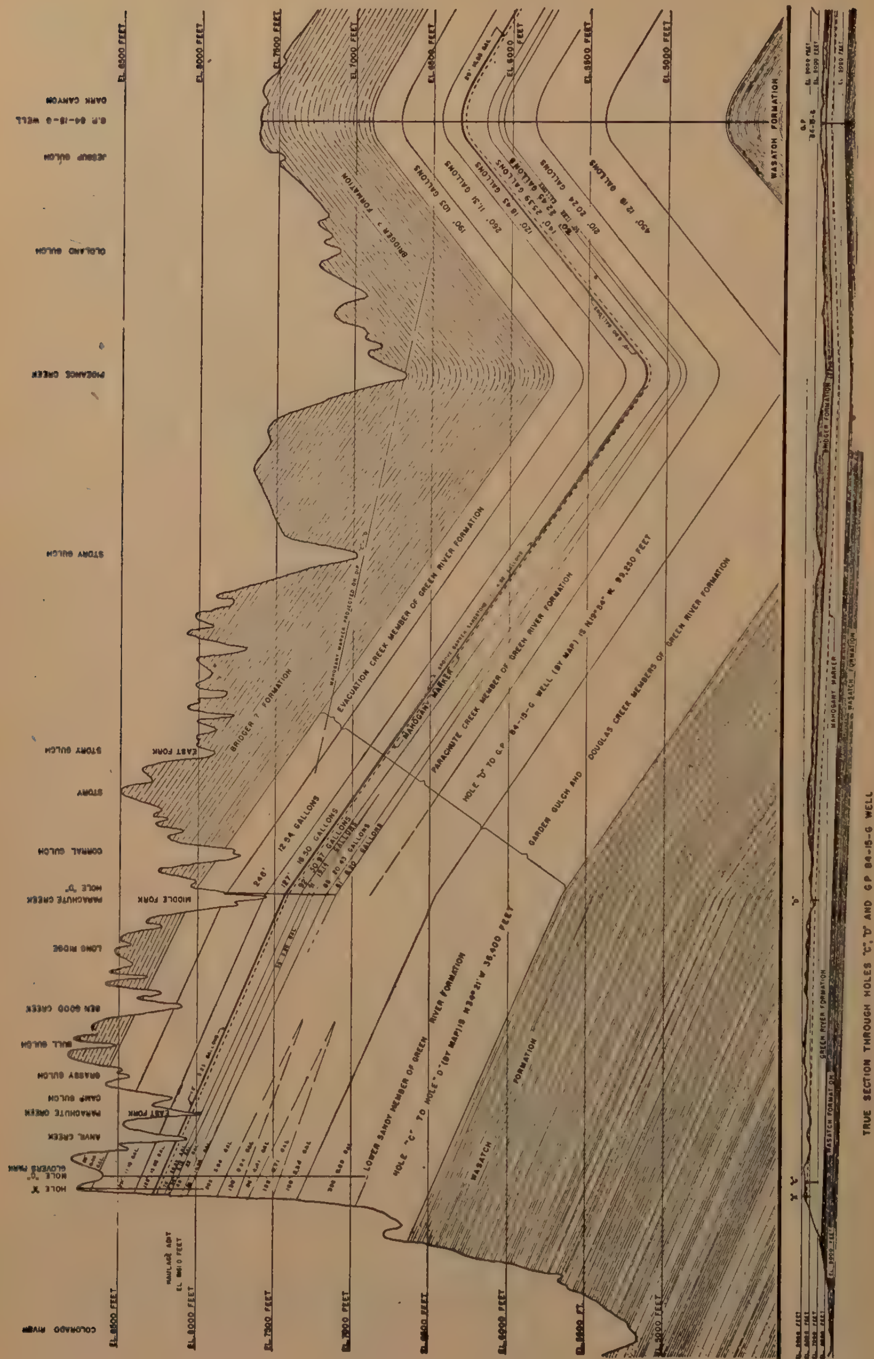

FIG 6—TRUE SECTION THROUGH HOLES *C*, *D* AND G.P. 84-15-G WELL.

Hole *C*, will extend under 1000 square miles. It is to be stressed, however, that considerably more core drilling would be required to substantiate the estimate of grade and tonnages of the oil shale in Colorado given in this paper. The estimates, however, are made on the best available data and appear conservative on the basis of the assumptions that have been made. The expected yield per square mile from the bed with the mahogany ledge, at Hole *C* is 100,000,000 bbl, at Hole *D* 128,000,000 bbl, and at Hole 84–15–G 159,000,000 bbl. Assuming that 1000 square miles of the Piceance Creek Basin would yield an average of 100,000,000 bbl per square mile, the total expected yield would be 100,000,000,000 bbl disregarding mining and retorting losses.

The bottom bed of the top oil-shale measure with the mahogany ledge would have to be mined by underground methods. The full oil-shale measure (Fig 4), however, could be mined as an open cut over large areas. The full measure at Hole *A* is 500 ft thick and averages 15 gal per ton; the yield of oil would be 300,000,000 bbl per square mile. By discarding the relatively low grade material at the top of the measure, the average grade could be increased.

Hole *C* penetrated 328-ft-thick oil shale that averaged 17 gal per ton. The medium grade[a] oil shale is more dense than the rich, and 13.5 cubic feet weigh a ton. A square mile will yield 275,000,000 bbl of shale oil.

Hole *D* samples showed that 407 ft of the top oil-shale measure has an average grade of 19.6 gal per ton; it may yield 390,000,000 bbl per square mile. The oil shale in the two lower measures at Holes *C* and *D* are not taken into consideration in this paper.

Hole 84-15-G indicated that the medium-grade oil shale was 1310 ft thick of an average yield of 15.75 gal per ton, or 1,000,000,000 bbl per square mile. These estimates include the oil-shale bed with the mahogany ledge.

It will be noted from Fig 4 that the grade of the oil shale varies greatly from foot to foot in the vertical column. By making different groupings of various thicknesses of oil-shale beds, different average grades and different estimates of the expected yield per square mile could be obtained. Fig 5 shows the average grades of a number of medium and low grade intervals of the section between Holes *C* and *D*. A slightly different grouping is shown in Fig 6.

It is assumed that the medium-grade oil-shale section capable of yielding over an average 15 gal of oil per ton including the bed with the mahogany ledge would yield 300,000,000 bbl of shale oil per square mile. It is estimated that this measure extends under 1000 square miles in the Piceance Creek basin; therefore, the total yield of oil would be 300,000,000,000 bbl of oil disregarding mining and retorting losses. By including lower-grade shale, this estimate could be increased considerably.

Utah

East-central Utah contains 4680 square miles of Green River formation of which 1600 square miles is covered by Bridger formation. An area equally large between the Uinta Mountains and the Duchesne River is covered by the younger Uinta formation and may contain Green River formation underneath. The logs of 24 sampled sections are available; 8 were taken in townships 24 and 25 E. in the Dragon-White River Station area, 5 were taken from Naval Reserve No. 2, 4 from the area near Soldiers Summit, and 7 from the southern rim of the Green River outcrop.

The 8 sampled sections from the eastern

[a] A bed of medium-grade oil shale assays 15 gal per ton or more throughout its minable thickness and includes the rich bed.

side of the basin averaged 378 ft in length and contained an average of 37 ft of better than 15-gal shale with 14 ft of better than 30-gal shale. The 16 remaining sections averaged 238 ft in length and contained an average of 10 ft of better than 15-gal shale and 3 ft of better than 30-gal shale. Although several new sampled sections have been taken since publication of the Winchester report,[10] there is not enough additional data to change materially his estimate of 92,150,000 tons of shale which would yield as much as 15 gal of oil per ton. He gives a total of 42,800,000,000 bbl of "Total Oil" for Utah in Appendix I of Federal Oil-Shale Conservation Report II.

No sampled sections of the large area north of the anticlinal high of the basin near the Duchesne River are available because of the overlying Bridger and Uinta formations; as the axis of the syncline is some 15 miles farther north, there is a possibility that this present syncline may represent the bottom of the old lake basin and that a large quantity of good-grade shale may be found in this area.

Wyoming

Southwestern Wyoming contains 9192 square miles of Green River formation of which 4200 square miles is overlain with Bridger formation.

Only eight sampled sections are available. These sections average 667 ft in length and contain 9 ft of better than 15-gal shale with 3 ft of better than 30-gal shale.

Five sampled sections were taken along the Green River from Green River south, one from the east edge of the main deposit near Rock Springs, two from outliers near Fossil, and one from the large deposit in southeastern Sweetwater County.

Because of the meager data available, no attempt is made to estimate the oil-shale reserves of Wyoming. However, Winchester,[11] who also had a number of short sampled sections to help guide him, estimated the reserves at 7,176,000,000 tons of oil shale that would yield at least 15 gal to the ton. His estimate of "Total Oil" for Wyoming in Appendix I of the Federal Oil Conservation Report No. II is 3,044,000,000 bbl.

Summary

Presently available sampled sections indicate the oil shale of Colorado contains 300 billion, that of Utah 42.8 billion, and that of Wyoming 3 billion barrels of shale oil.

Necessarily, any estimate made at this time from the meager data available is sketchy. The oil content of at least 50 pct of the Green River formation in Utah and 90 pct in Wyoming is unknown. Only one sampled section is available for every 39 square miles of Green River formation in Colorado, 195 square miles in Utah, and 1150 square miles in Wyoming. If the present recessed areas conform with the lows of the old lake bottoms, and conditions were as favorable for deposition of organic material, as they were in the Piceance Creek Basin, a comprehensive drilling program may block out oil reserves in the Green River formation considerably more than the above estimate.

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Oil-shale Mining

By Tell Ertl,* Member AIME

(Denver Meeting, September 1947)

Abstract

The term oil shale is defined. Foreign oil-shale developments are outlined briefly. The richest and most extensive oil-shale deposits in the United States lie in western Colorado. The Bureau of Mines is opening two adjacent areas for underground mining in western Colorado. From the first area the oil shale is mined selectively as required by the retorting plant. The second area is being developed as a unit of a full scale oil-shale mine to ascertain the most practical methods of mining oil shale and to determine costs. In both of these mining areas, research will be carried on to develop new and improved practices for mining oil shale.

Introduction

Oil shale is a sedimentary rock containing a solid mineraloid of indefinite composition known as kerogen. On heating oil shale, the kerogen undergoes thermal decomposition and some of the vapor products of the decomposition can be condensed as shale oil. Oil from shale can be a major source of liquid fuels since extensive deposits of oil shale are known to exist throughout the world. The United States considers the establishment of an oil-shale industry only when doubt exists of the adequacy of the domestic supply of crude petroleum.

On the other hand, oil shale is not strange to foreign oil men. The industry is an old one in other parts of the world. The French industry has been in existence since 1838, the Scottish since 1859, the Australian since 1860, the Estonian and Swedish industries since World War I, and the Manchurian industry since 1929.

The most highly exploited oil-shale deposits are the Carboniferous shales of Scotland. About 20 seams ranging from 4 to 12 ft in thickness are worked. The yield during recent years in Scotland has been 18 to 25 gal of shale oil per ton, from 3,000,000 tons per year. The French and Swedish oil-shale deposits are of lower grade than the Scottish. The Estonian oil-shale deposits are 7 ft thick, and the oil yield averages 50 gal per ton. Over 1,000,000 tons are mined each year, half of which is used directly as fuel to substitute for coal and the other half is used for the production of oil.

Immense deposits of oil shale that will yield 10 to 15 gal per ton exist in Germany. Because of the impending loss of the Rumanian and Polish oil fields and the bombing of synthetic liquid fuel plants, the Nazis in 1943 started a large-scale oil-shale program in Germany. By V-E Day, it is said, oil-shale production had reached the rate of 2500 tons per day and rapid expansion of the industry was imminent.

Australian oil shale, known as torbanite, occurs in beds 2 to 6 ft thick. It is of a very high grade and on retorting yields 80 to 160 gal per ton. The oil-shale industry of Manchuria was the largest in the world during the past decade. The well-known Fushun coal deposit in Manchuria has an overburden of 500 million tons of oil shale about 450 ft thick that will yield 10 to 15 gal of shale oil per ton. The oil shale is

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stripped in mining the coal; therefore, no mining costs are charged to it. Despite the low grade of the oil shale, the industry operated profitably without subsidy in competition with imported petroleum. Before World War II, production of shale oil in Manchuria was one million barrels annually, and in 1943 it had increased to two million barrels. For the production of two million barrels a year six million tons of oil shale had to be mined and treated.

As compared with the low-grade oil shales mined on a commercial scale in Scotland, France, Sweden, Germany, Spain and Manchuria, and the thin but rich oil shales mined in Estonia and Australia, Colorado oil shale occurs in thick beds of good grade. Carl Belser[1] has pointed out that oil shale that will yield 30 gal per ton can be mined in hundreds of square miles of western Colorado from beds 50 ft or more thick and that the amount of shale oil that can be produced from Colorado alone is many times the total amount of petroleum produced since the inception of petroleum production. If the United States were not a petroleum-producing nation, doubtless it would have the most important oil-shale industry in the world because of the size and grade of its oil-shale deposits.

The Bureau of Mines Oil-shale Program

Public Law 290, 78th Congress, which authorized the design, construction, and operation of demonstration plants to produce synthetic liquid fuels from coal, oil shales, agricultural and forestry products and other substances was approved on April 5, 1944. Soon thereafter, the Office of Synthetic Liquid Fuels was set up, and investigations were begun for the selection of sites for demonstration plants.

The search for a site for an oil-shale mine and plant was centered in western Colorado because that area contains the richest and most extensive oil-shale deposits known in the United States. The uniform, flat-lying oil shale forms a plateau 2000 to 4000 ft above the Colorado River and its tributary valleys and outcrops toward the top of the steep valley walls.

Fig 1 represents a generalization of the oil-shale outcrops throughout the area. The surface of much of the plateau consists of sandy and limey shale which is essentially barren. Below the barren shale is a 400-ft horizon of oil shale that will yield one-third barrel per ton on retorting. Directly below the 400-ft horizon is a 70-ft thickness averaging seven-tenths of a barrel per ton, which includes a 25-ft interval averaging nearly a barrel per ton. The outcrop of the 70-ft section forms a distinct overhanging cliff throughout most of the western Colorado oil-shale area.

Neither the 25-ft or 70-ft interval can be mined by surface methods on a large scale since no sizeable area exists from which the overlying beds have been eroded. The low-grade oil-shale overburden, as shown in Fig 1, ranges in thickness from 300 to 1000 ft and averages 500 ft. The mining of oil shale carried on by the Bureau of Mines will be from the 70-ft section or from selected portions of the 70-ft section. This interval also appears to offer the best opportunity for commercial exploitations.

Investigations indicated that a site near Anvil Points, 10 miles west of Rifle, Colo., and 200 miles west of Denver, was the most suitable for the development of an oil-shale mine and the erection of an oil-shale demonstration plant of the size authorized by Congress. This site was recommended to the Secretary of the Department of the Interior and was approved early in 1945.

The oil-shale mining division was established on May 1, 1945, and was assigned two separate tasks. The first task is to mine

[1] Carl Belser: Oil-shale Resources of Colorado, Utah and Wyoming. Paper just preceding in this volume.

selectively various grades of oil shale from the 70-ft section as required by the plant. The second task is to ascertain the best practical methods of mining oil shale and to determine costs. A description of the progress of the oil-shale-mining program follows.

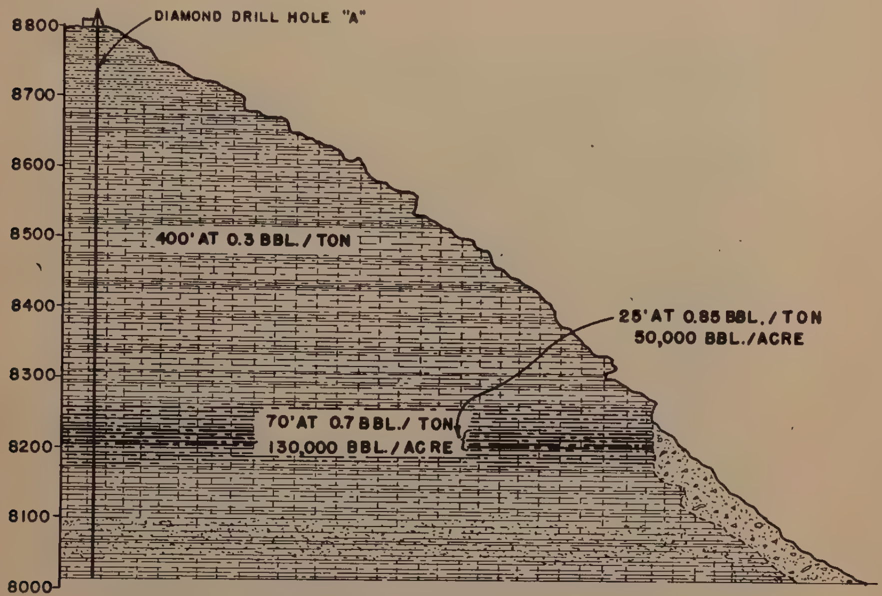

FIG 1—SECTION OF TOP OIL-SHALE MEASURE.

Mine Surface Development

The oil-shale mine is 9000 ft horizontally and 2500 ft vertically from the plant site, at an elevation of 8200 ft above sea level, and at the base of the cliff that forms the outcrop of the 70-ft section (Fig 2).

The construction of a road was begun as soon as the sites of the plant and mine were approved (Fig 3). A pioneer grade reached the mine by September 1945, grading and stabilization of the roadbed were completed in 1946, and surfacing of the road with river gravel was completed in the spring of 1947. The road has a general grade below 10 pct, with the exception of several rises up to 14 pct, and the sharpest curves have a radius of 40 ft. Much of the road has a southern exposure; therefore, snow problems are not serious.

A mine yard of one acre in area was excavated at the base of the cliff (Fig 4). A combination warehouse and office building, a change house, a shop building containing the air compressors, and an oil house have been erected. All buildings are of fire-resistant construction and consist of steel frames covered with transite or cemesto board. A telephone line and a 13,800-v power line were built from the plant site to the mine. A water supply was developed on the plateau above the mine, and the water is piped into the mine through a core-drill hole drilled from the plateau for exploratory purposes.

Mine Underground Development

Mining is done in two areas: one has been developed for the selective mining of oil shale from various horizons in the 70-ft bed; the second is being developed for mining the 70-ft bed by underground quarry methods to demonstrate on a unit

commercial scale low-cost oil-shale mining methods.

Selective Mining Area

Fig 5 shows the work done to July 1, 1947, in the area being developed for lying the 70-ft bed. A short, inclined raise also has been driven from the ventilation adit to the roof stone. The tops of the raises are connected by a series of openings just below the roof stone. A fan mounted in the ventilation adit forces fresh air into

FIG 2—OIL-SHALE DEMONSTRATION MINE AND PLANT SITE.

selective mining. A haulage adit driven in low-grade oil shale below the 70-ft minable section enters the cliff at a right angle. A parallel opening, called the ventilation adit, is in the minable oil shale. Two vertical raises extend from the haulage adit through the minable section to the roof stone over- the mine to all mine workings through the various openings.

Oil-shale requirements at the retorts are variable and may be from any of eight divisions of the 70-ft interval. Each of these eight divisions varies in thickness, grade, and amenability to retorting. To satisfy

the requirements of the retorts, a number of rooms have been started from the side of one of the raises above the haulage adit. Small quantities of oil shale have been mined from each of five separate divisions of the 70-ft bed, and relatively large quantities have been mined from two of the divisions.

FIG 3—MINE SITE.

Underground Quarry

The underground quarry is being developed to demonstrate a low-cost mining method for exploiting the 70-ft bed; the work will be done on a unit commercial scale. Fig 6 shows the method of mining that first will be demonstrated. A horizontal opening, 25 ft high and 60 ft wide, directly under the roof stone of the 70-ft minable thickness of oil shale will form the top bench of the underground quarry. This horizontal opening will be extended in two directions; one along the strike and the other up the dip of the bed (5 pct). Pillars 60 by 60 ft in area, comprising 25 pct of the oil shale, will be left between the horizontal openings.

The section of oil shale that extends 22.5 ft below the top bench will be mined as a

second bench. In a commercial mine a third and lower face, also 22.5 ft high, would be worked similarly to the second bench. The cost of mining would be the

In order to mine at low cost, the operation will be mechanized. A drill carriage is being built with which two miners will be expected to drill enough holes to break over

FIG 4—MINE YARDS AND BUILDINGS.

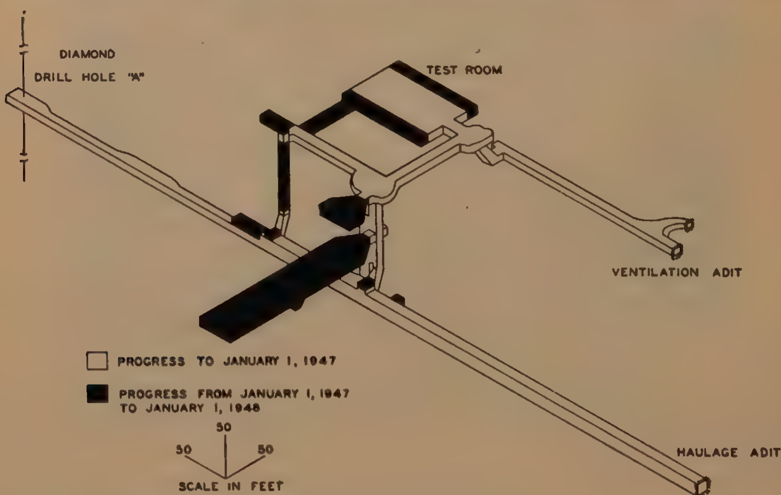

FIG 5—OIL-SHALE MINE.

same from both the second and third benches; therefore, the third face need not be mined to determine the overall mining costs.

1000 tons of rock per shift. A 3-yd electrically-driven shovel is on order, and a 3-yd overshot-type loader mounted on a diesel-driven tractor has been delivered; they

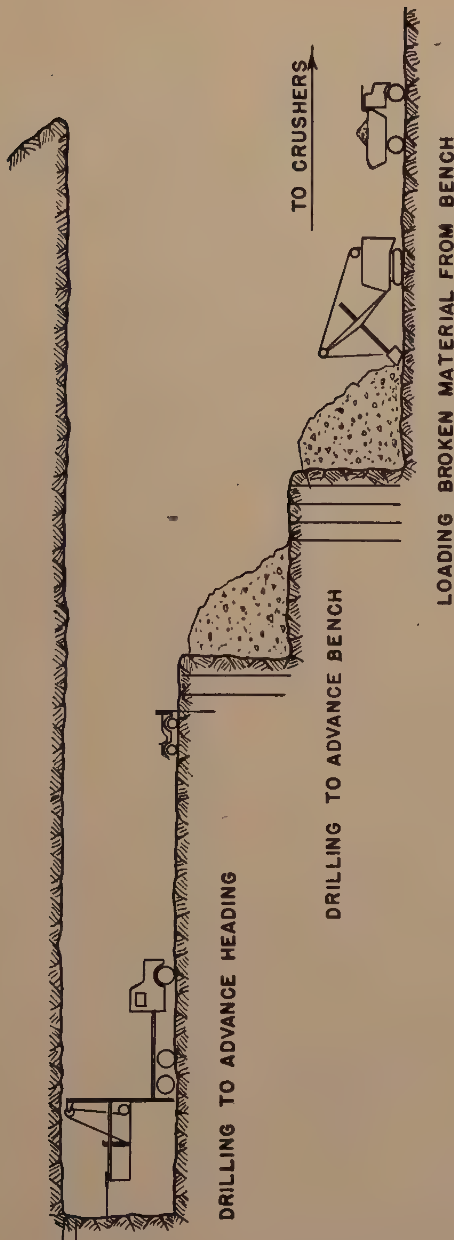

FIG 6—UNDERGROUND QUARRY.

will be used for loading broken oil shale into trucks. Each loader is expected to handle over 1000 tons of oil shale per shift. The broken oil shale will be hauled by 15-yd-capacity diesel-driven trucks to the plant or to a stock pile.

Mining Research

A comprehensive program of mining research and of mining investigations is under way to learn how to mine the oil shale cheaply. The mining studies are made in the laboratory or in either of the two mining areas; most of the commercial-scale research, however, will be done in the underground quarry.

Particular emphasis to date has been placed on a study of the character of the oil shale. Extensive laboratory investigations of the physical properties of the oil shale have been made at Columbia University, New York City, and at the Bureau of Mines stations at College Park, Md., and Pittsburgh, Pa. In addition, the oil shale is observed carefully during current mining operations. Fig 5 shows a test room that has been excavated in the selective mine to determine the strength of the roof stone overlying the 70-ft minable bed. The room is 70 by 100 ft in area, and the roof is unsupported. Daily measurements of the sag of the roof and daily recordings of the rock noises are made; no indications of excessive stresses or imminent failure of the roof have been noted. The research work on the physical properties of the oil shale has indicated that large rooms can be worked safely in the minable oil-shale bed. Large rooms permit the use of large units of equipment with a corresponding large output per man shift.

Pencil studies of the cost of mining oil shale indicate that the major cost item will be breaking the rock. Extensive studies are under way to determine the most economical methods for drilling oil shale, the best type of drill to use, the optimum size of hole to drill, and the proper spacing and placing of drill holes. A companion problem of determining the most efficient explosive for breaking the rock is receiving attention. The loading and transportation of the broken oil shale also require study.

Adequate ventilation of the mine workings is a necessity, since diesel engines are used underground and relatively large quantities of explosives are required for breaking the rock; the ventilation problem has a high priority. Numerous bottle samples of the mine atmosphere have been taken and weekly methane and carbon monoxide tests have been made underground. No natural hydrocarbons or other natural harmful gases have been detected.

Doubtless, the present plans of mining will be modified as experience in handling the rock is gained. The goal of the oil-shale mining program is to learn to mine the rock so cheaply that the total cost of mining and retorting the oil shale and refining the shale oil into commercial products will be low enough to encourage private enterprise to establish a new industry.

Oil-shale Processing

By J. D. Lankford* and Boyd Guthrie*

(Denver Meeting, September 1947)

Abstract

A progress report on the oil-shale and shale-oil processing research program at the U. S. Bureau of Mines Oil-Shale Demonstration Plant. Legislation providing for the program and aims are briefly noted. The remoteness and rugged nature of the terrain at the plant site are important factors in construction and operations. Large-scale units now in operation are the crushing plant and two 40-ton N-T-U retorts. These are described in detail. Under construction are several retorting pilot plants and a 200 bbl per day refinery. The refinery incorporates several types of thermal operation, three-stage low-temperature acid treating, doctor sweetening, and rerunning.

Data are presented on typical N-T-U retort runs. Yields of 90 to 100 pct of assay are realized on 30 gal to the ton shale with a retort cycle time of 18 hr. Data also are presented showing a comparison of a Mid-Continent petroleum and N-T-U shale oil. This comparison indicates that shale oil has a high pour point, low API gravity, and contains about 0.8 pct sulphur and 2 pct nitrogen. The naphtha fraction contains 3 pct tar acids, 9 pct tar bases and 50 pct olefins. The problems involved in refining shale oil into usable products are discussed in detail.

Introduction

The Bureau of Mines oil-shale program now under way at Rifle, Colo., was begun in July 1944 under the provisions of the Synthetic Liquid Fuels Act, which was passed in the spring of that year under the sponsorship of Senator Joseph C. O'Mahoney of Wyoming and Congressman Jennings Randolph of West Virginia, aided by Michael W. Straus, former Assistant Secretary of the Interior, and others. The oil-shale plant is only a part of the Office of Synthetic Liquid Fuels, Bureau of Mines, which has under way projects to develop synthetic liquid fuels from coal and other solid materials at Pittsburgh and Bruceton, Pa., Morgantown, W. Va., Louisiana, Mo., as well as the Petroleum and Oil-Shale Experiment Station at Laramie, Wyo., and the oil-shale demonstration plant at Rifle.

The oil-shale program is entirely experimental. It is not intended that oil will be produced in great quantities. Production will be limited to the volume obtained from plant-scale experimental operations, which will be kept to the minimum size needed to develop techniques and processes and to demonstrate costs.

After the passage of the enabling act in the summer of 1944 a survey of the oil-shale resources of the Nation was made to determine the most suitable general area in which to establish the demonstration plant. The most suitable area was found to be in the Rifle-De Beque area in Garfield County, western Colorado. Bureau of Mines field parties covered this entire area thoroughly

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in the late summer and fall of that year, conducting site surveys. The demonstration plant was constructed at Anvil Points about 10 miles west of Rifle, Colo., on the exception rather than the rule. Some of the oil-shale lands can be classed as the most remote, arid and wild regions in the United States.

FIG 1—AERIAL VIEW OF THE OIL-SHALE DEMONSTRATION PLANT SITE BEFORE CONSTRUCTION WAS BEGUN.

Mine site at upper left at convergence of cliff and hogback. Plant site at extreme right center on wooded mesa. Housing site in cleared center of picture. Photograph by the Bureau of Mines.

Naval Oil-Shale Reserves Nos. 1 and 3, as a result of these surveys.

Demonstration Plant

Site Location

The site chosen was rugged and primitive (Fig 1), but it offered more advantages than could be found in any of the other sites examined. The advantages were water, power, rail and highway transportation, fair proximity to towns and villages, and reasonable access to large quantities of oil shale in the Green River formation. In populated and developed areas most of the foregoing facilities might seem to be insignificant, but in the oil-shale regions of Colorado, Wyoming and Utah they are the

Construction

Construction work, begun during the summer of 1945, still comprises most of the work being done. It was necessary to build a complete utility system, consisting of a water pumping, treating, and distribution system, sewerage system, almost 10 miles of roads, a village of 50 dwelling units, service shops, garage, offices, storage facilities, power substation and transmission lines, boiler plant, laboratories, processing units for crushing, conveying, and storing shale, and retorts to produce oil from the oil shale.

As the construction work was going forward, the mines were being developed by the Oil-Shale Mining Division to be ready

to produce and deliver shale to the plant when operations commenced.

Except for erection of the crushing and storage plant and the two N-T-U retorts, which was done under contract, the major part of the preliminary work was done by Bureau of Mines employees. The work of building the project from sagebrush conditions was undertaken and carried out under extremely adverse circumstances as concerns labor, materials, and equipment.

The greater part of the construction work to provide facilities had been completed, and the operating phase had been started when the project was dedicated May 17, 1947.

Processing Program

Organization

The processing program at the oil-shale demonstration plant is divided into four units, which are grouped into what is known as the processing section. In the organization these units are known as the retorting unit, the refining unit, the engineering-development unit and the laboratory unit. The work is segregated according to function.

In the retorting unit oil shale from the mine is crushed, screened, stored, blended, weighed and charged to the retorts, where the oil is extracted by heat and the spent shale is discarded.

After the refining unit is constructed shale oil will be delivered from the retorting unit to the refining unit for processing into finished products.

Pilot-plant work to develop processes for retorting and refining is undertaken by the engineering-development unit. From fundamental chemical and physical data furnished by the Laramie research laboratories and engineering and other data available in the literature, patents, and foreign operations and from cooperating commercial firms, the technicians in this unit design new processes and pilot equipment for the extraction of oil from oil shale and the refining of shale oil into usable products.

Control work in the retorting, refining, and pilot operations is performed by the laboratory unit.

Crushing Plant

A variety of shales can be produced from the selective oil-shale mine.[1] An arbitrary classification of the strata in the mine has made it possible to obtain for retorting experiments shale of almost any richness ranging between 16 and 70 gal per ton. The shales can be blended for any oil content desired, as the retorts are being charged by means of three large storage bins equipped with continuous weighing devices.

The crushing plant is equipped to produce shale in any size, up to 6 in. in diameter, with close size classification. Mine-run shale is delivered directly by trucks to the crushing plant and, after passing through the primary and secondary jaw crushers and screens, the material is carried into the storage bins by conveyor belts (Fig 2).

Retorting Plant

Oil Shale

Oil shale is classified as to coking tendency, as well as richness. In general, as the scale of richness increases so does the coking tendency. When heated, the richer shales form dense agglomerations that cling together strongly and clog the retort. Oil shales in other parts of the world exhibit the coking tendency, but the Green River shales are noted for this characteristic. For this reason extraction equipment which has been developed for operation on many foreign shales has proved inadequate for Green River shales.

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[1] Tell Ertl: Oil-shale Mining. Paper just preceding in this volume.

Shale oil is the product obtained from a substance called kerogen, which is present in oil shales. Kerogen is a solid organic material dispersed throughout oil shale; it is unaffected by the usual solvents for fats and oils, but when heated to a temperature of about 700°F and higher it is converted into vapors which form shale oil upon condensing. In essence, the retorting of oil shale can be called destructive distillation.

FIG 2—THE N-T-U-RETORTING PLANT AND THE SHALE-CRUSHING, SCREENING AND STORAGE-EQUIPMENT BUILDINGS VIEWED FROM THE SOUTHWEST.
Photograph by the Bureau of Mines.

N-T-U Retorts

At present two N-T-U retorts are producing shale oil. Each of these batch retorts has a charging capacity of 40 tons of shale. The cycle of operations requires about 18 hr per batch for each retort, though the operating cycle varies according to the type of shale and conditions of operation.

The N-T-U retort invented and developed in the United States has been operated commercially in Australia and England. N-T-U retorts were constructed at Rifle for the primary purpose of obtaining retorting rates, heat transfer, and other thermodynamic data on plant-scale equipment; to develop techniques; to train personnel; and to produce oil for other experimental operations. Accordingly, the retorts were equipped with the latest types of temperature, pressure, and flow instruments and controls. Complete operating data are obtained and recorded from each run for careful study and use in developing improved processes. The N-T-U retorts likewise are proving invaluable in providing a fund of plant-operating experience that is applicable to other processes in such fields as handling shale, pumping and storing shale oil, maintenance of equipment, and design of equipment to meet the peculiar needs of the solid oil shale and liquid, or somtimes semiliquid shale oil.

The N-T-U retorts have proved satisfactory in handling the rich coking shales. By careful control of operating conditions coking can be minimized, but even when large masses of coke are formed the retort can be dumped without difficulty through the hinged bottom that can be opened wide in a few seconds by means of a powerful

hydraulic cylinder. When the bottom is opened the entire spent-shale charge falls from the retort. The downward flare of the retort prevents the coked mass from clinging to the retort walls.

cooler followed by a scrubber tower having two water-spray sections. An oil-water separator is provided for each spray section. Air and gas are forced through the system by multistage air and gas blowers.

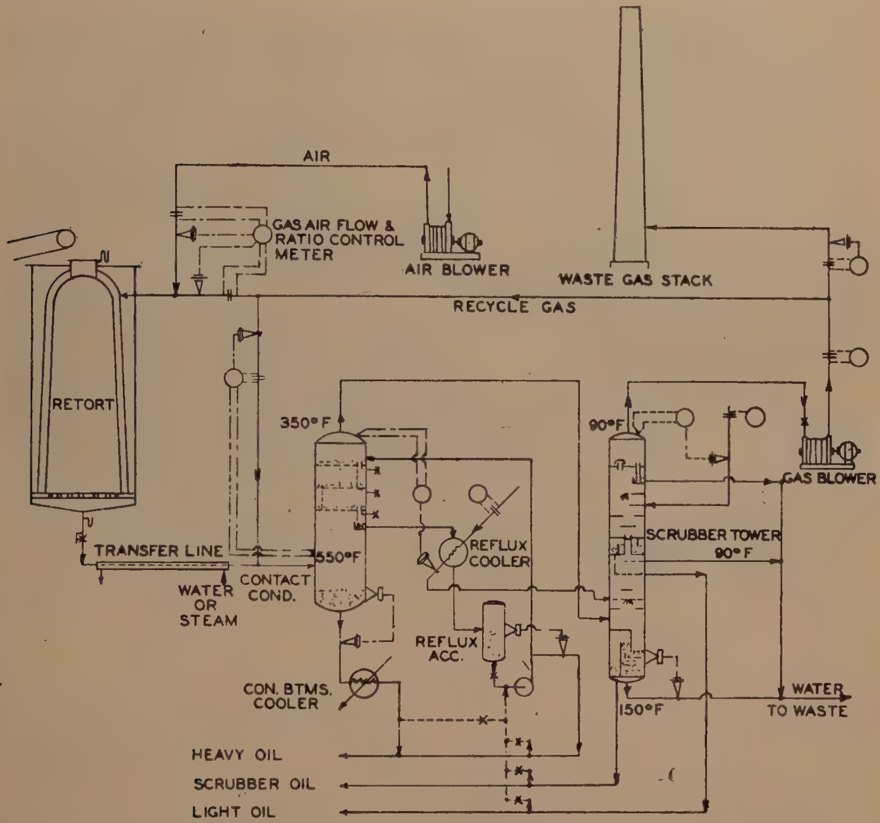

FIG 3—N-T-U RETORT FLOW DIAGRAM.

In general, the N-T-U retort is a cylindrical steel shell with a domed firebrick lining tapering inward toward the top (Fig 3 and 4). Shale is charged through a removable manhole at the top. The bottom of the retort is closed by means of a hinged grate, which supports the shale charge. An offtake line for hydrocarbon vapors and combustion gases leads from an airtight pan fastened beneath the grates to the recovery system.

The recovery system consists of a three-tray bubble tower with a reflux pump and

Shale oil is withdrawn from the bottom and trays of the bubble tower and from the oil-water separators in the scrubber tower.

After the retort has been charged with approximately 40 tons of shale, a fire is kindled on top of the shale bed, using kindling and a small quantity of furnace oil or shale oil. The top manhole is left open and a draft is drawn downward through the shale bed with the gas blower. As soon as combustion is under way the manhole is closed and air is forced into the top of the retort with the air blower. The air stream

is diluted with controlled amounts of combustion gas from the gas blower to reduce the amount of oxygen and thus control the temperatures and combustion rate in the retort.

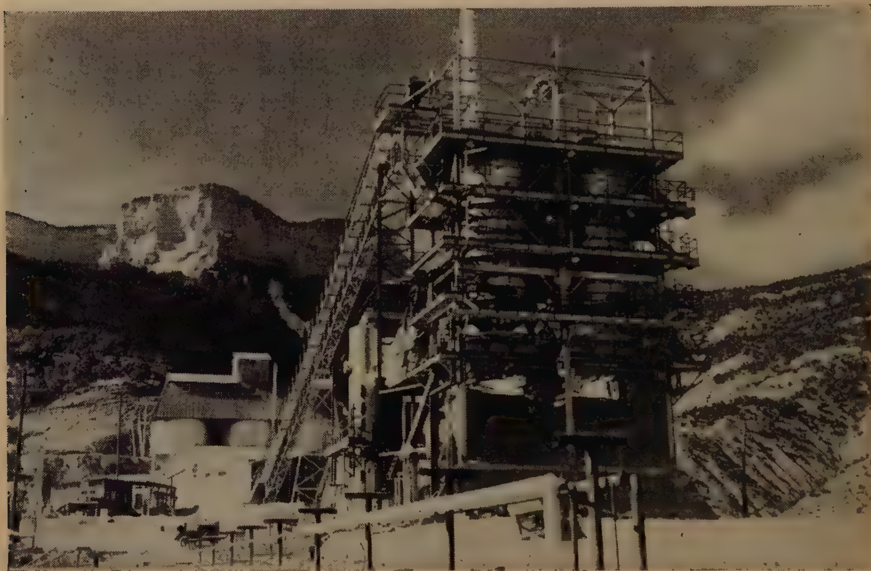

FIG 4—SOUTH VIEW OF N-T-U OIL-SHALE RETORTS SHOWING SHALE BINS AND BELT CONVEYOR. Oil-shale cliffs in the background rise 3000 ft above the retorts. Photograph by the Bureau of Mines.

Retorting takes place in the retort below the combustion zone owing to the hot gases passing downward through the shale bed. As the shale is retorted, the released oil and vapors are drawn from the bottom of the retort through the grates and into the recovery system, where the vapors are condensed and the oil is withdrawn.

During the retorting cycle the combustion zone moves downward toward the grates and expels the shale oil ahead of it. Fuel for the process is provided by the fixed carbon remaining in the shale after the oil has been expelled.

To date about 50 runs have been made in the two N-T-U retorts. Shale assaying about 30 gal of oil per ton was used in most of them. These runs have been varied widely to establish the best operating conditions, to locate flaws in the design, and to develop operating techniques.

In a typical run the shale charge is 40 tons; air is supplied to the retort at a rate of 500 cfm and recycle gas at a rate of 1000 cfm. The highest retort temperatures in a typical run are 1500 to 1700°F. In some runs, however, temperatures of 2400°F have been reached. The gases leaving the retort are noncombustible and may contain 30 pct CO_2, 1 to 3 pct oxygen, 1 to 3 pct carbon monoxide, a small amount of hydrocarbon gases, and nitrogen. At times the oxygen content is reduced below 1 pct and the carbon dioxide runs even higher than 30 pct owing to decomposition of carbonates in the shale. The yield of oil from the N-T-U retort is generally close to the assay value of the shale charge. Yields of 90 to 100 pct of the assay value can be obtained by direct condensation and increased by recovering light oil in the retort gases. With the 30-gal shale charge and conditions given above, a cycle time of

approximately 18 hr is required to charge the retort, make the run, discharge, and prepare for the next run. This cycle can be varied somewhat by increasing or decreasing the volumes of air and recycle gas. Combustion, however, cannot be maintained in the retort with less than a 1:4 ratio of air to recycle gas; and if the ratio of air to gas greatly exceeds 50 pct, the temperatures are excessive and the mineral matter in the shale slags. Yields of oil suffer at too great retorting rates because of high velocities through the shale bed and recovery system.

Refining

Shale Oil

The retorts produce crude shale oil, which must be refined before it can be utilized for any purpose other than boiler fuel. As yet no mention has been made of the properties of this crude product. In order to avoid any confusion regarding the distinction between shale oil and petroleum it should be stated that shale oil definitely is not petroleum. It is a black, viscous liquid, with a high pour point, but here its resemblance to petroleum ceases. While the oil produced by different types of retorts from the same shale may differ owing to the severity of thermal treatment, N-T-U oil reasonably may be considered to be fairly representative of the shale oil for initial refinery experimental work. Table 1 shows a comparative analysis of N-T-U shale oil and a typical Mid-Continent petroleum from Oklahoma City. This tabulation shows clearly some of the differences between shale oil from the N-T-U process and a Mid-Continent petroleum. It should be noted in the tabulation that the petroleum contains no nitrogen, whereas the shale oil contains almost 2 pct and the yield of straight-run naphtha from shale oil is low compared to the yield from petroleum. No tar acids or bases are present in the petroleum naphtha, while 3 pct tar acids and 9 pct tar bases are found in the shale naphtha. It is interesting to observe also the unsaturated

Table 1—*Comparison of Mid-Continent Petroleum and N-T-U Shale Oil*

Type	N-T-U Shale Oil	Oklahoma City Crude Petroleum
Crude		
°API at 60°F	20.4	39.0
Sulphur, pct	0.78	0.14
Nitrogen, pct	1.97	
Pour point, °F	80	5
Viscosity, s.u.s. at 100°F	200	45
Distillation Summary		
Naphtha, pct	3.6	28.4
Light distillate, pct	19.8	25.0
Heavy distillate	25.6	18.6
Residuum, pct	49.8	26.3
Loss, pct	1.2	1.7
Naphtha Properties		
Tar acids, pct	3.0	
Tar bases, pct	9.0	
Components:		
Paraffins, pct	34 (Paraffins and Naphthenes)	61
Naphthenes, pct		29
Olefins, pct	50	
Aromatics, pct	16	10

character of the shale naphtha where the olefin content represents 50 pct of the total. Although the analysis of components is shown only for the naphtha fractions, it is fairly indicative of the nature of the entire crude.

Fractions obtained from straight distillation of shale oil are not of good quality. The straight-run gasoline has an octane rating below 60; is high in ring-type sulphur, tar acids, and tar bases; is gum-forming and has an extremely poor color stability; and is deficient in the light ends required for volatility for use as motor fuel. The straight-run Diesel-oil fraction is of marginal quality having a low cetane rating, a high pour point, and a high carbon residue. Kerosene meeting the usual requirements cannot be made by the straight distillation of shale oil. The crude shale oil or residuum from topped shale oil is satisfactory for boiler fuel, though the latter has a high viscosity and pour point.

At present asphalt or road oil of suitable quality has not been prepared from shale oil.

The foregoing discussion is a disturbing and pessimistic picture of shale-oil utilization, and admittedly the refining of shale oil into usable products presents unusual challenges. Shale oil is not a virgin stock in the usual sense of the term but is considered a cracked product when it emerges from the parent rock in the retort and for this reason presents many refining problems that are not inherent to petroleum.

In the synthetic fuels picture motor fuel and diesel oil are of predominant importance. Aviation gasoline probably can be manufactured from shale oil, but perhaps not economically. On the other hand, the manufacture of jet fuels in the kerosene boiling range may appear economically favorable. Nevertheless, experimental work will be carried out to investigate all types of synthetic fuels from shale oil.

Since shale oil is highly unsaturated, the suggestion that it be hydrogenated is only natural. One must remember, however, that the equipment and processing costs for full or destructive hydrogenation are relatively high. Shale oil after mild hydrogenation still would require further processing because some of the fractions obtained from such hydrogenated shale oil would not be suitable for direct use. Therefore, hydrogenation must be considered at the time as a feed-stock preparation process for other refining treatment. Studies on both destructive and mild hydrogenation of shale oil and oil shale are being carried on, however, in the laboratory to determine the feasibility of this processing technique.

There are numerous other processes that may offer possibilities in connection with shale-oil refining. These processes include polyforming, hydroforming, isoforming, cycloversion, polymerization, and aromatization. Of the above, the aromatization and cycloversion processes appear to offer the most promise because of the unsaturated character of shale oil. It is planned to carry on further studies aimed at the utilization of these and other processes as the refining experimental program continues.

Refining Plant

After studying carefully the major processes designed for the refining of petroleum since little has been published on similar processes for shale oil that will produce the finished products that will comply with the present strict specifications for petroleum products, it was decided that thermal cracking offered the best means of processing shale oil for initial experimental operations. In addition to the possibility of obtaining stocks of various boiling ranges from a thermal process, clean charge stocks will be available for catalytic processes.

A small-scale refinery now is in the process of construction at the Rifle project (Fig 5 and 6). This refinery will be the smallest size that can be operated as a commercial unit. It will have a daily charging capacity of about 200 bbl of shale oil, depending on the type of operation. Extreme flexibility is incorporated in this refinery for different types of operations. The distillation unit can be operated as an atmospheric topping still, as a thermal cracking unit on gas-oil recycle operation with reaction chambers, as a delayed coking unit using coke chambers, or on charging naphtha as a reforming unit. A stabilizer and absorber are provided for handling light ends, and a naphtha rerun column will be operated in conjunction with it for finishing treated stocks.

A continuous three-stage low-temperature acid treating plant will be used for treating the light stocks, and the doctor process will be used for sweetening.

If deliveries of equipment are main-

FIG 5—AERIAL VIEW OF PLANT AREA SHOWING N-T-U RETORTS IN THE RIGHT FOREGROUND AND REFINERY AREA IN THE LEFT CENTRAL PART OF THE PICTURE.

The circular depressions are excavations for storage tanks in the refinery area. Photograph by the Bureau of Mines.

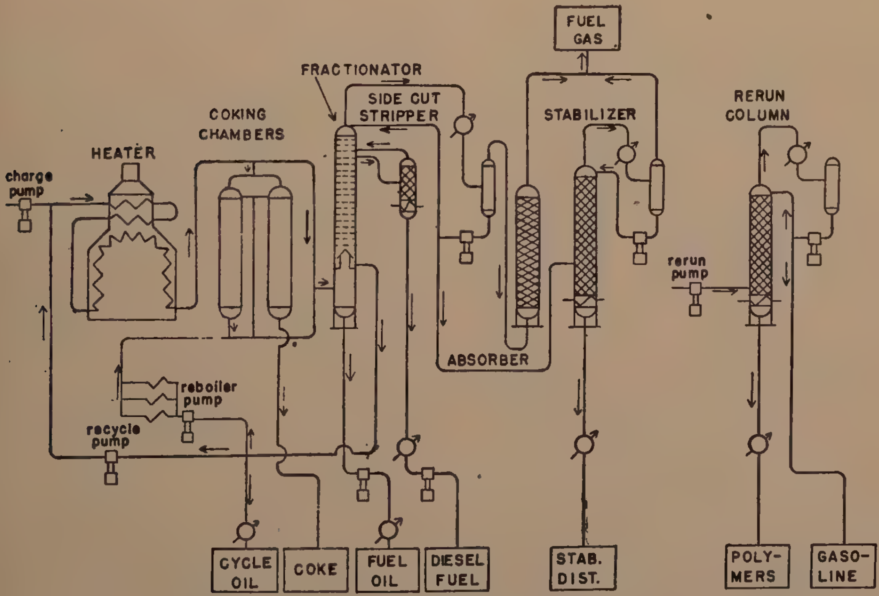

FIG 6—SHALE-OIL REFINERY COKING-CRACKING UNIT.

tained, it is planned to have the refinery in operation by the summer of 1948.

Pilot-plant Program

Retorts

The work of the engineering and development unit is considered of prime importance at the oil-shale demonstration plant. This division will undertake the pilot-plant investigations needed to prove new processes for retorting and refining that have shown promise in the research laboratory. At present one pilot retort is ready for operation, and another is being constructed. The pilot retort is the Jodavis flash carbonizer retort, which had previously been developed at the Bureau of Mines station, Pittsburgh, Pa., for low-temperature carbonization of coal. The other retort is termed the "Gas-Flow" and was designed by the Rifle staff.

The Jodavis retort is a small batch unit holding a charge of about a ton of shale (Fig 7). Retorting is accomplished by forcing hot gases through a fixed shale bed until all of the oil has been expelled. The hot gases are heated by two recuperative pebble stoves, which can be fired alternately by burning the waste gases from the retort. A Jodavis retort of very similar construction, at the Wilson Dam Station of the Tennessee Valley Authority, was operated on several grades of Green River shale under cooperative agreements with the Tennessee Valley Authority last year and the favorable results of this work led to the construction of the unit at Rifle. As the Jodavis retort is a small-batch unit, it does not offer special promise as a commercial process by itself, but it has several unique features that do offer promise and can be studied carefully in operating the unit. These features include the use of recuperative pebble stoves for heating hot gases, a principle of retorting with hot gases rather than with internal-combustion gases as in the N-T-U, and the utilization of shale gases which, from the Jodavis retort, are combustible. Studies of the behavior of the gases flowing through fixed shale beds at elevated temperatures under varying conditions of particle size and gas velocity also will be undertaken. Valuable information will be obtained on the behavior of oil shale under different retorting conditions in regard to coking, decomposition of mineral constituents, and the pyrolytic conversion of kerogen, with particular reference to the thermodynamics of the reactions. In all pilot-plant work materials used for retort construction capable of withstanding the severe conditions existing in retorts will be studied thoroughly for application to larger commercial equipment.

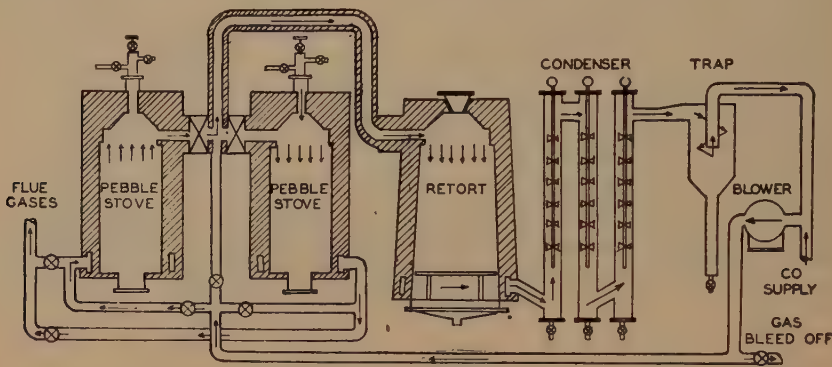

Fig 7—Flow diagram of flash carbonization process in a Jodavis retort.

The Gas-Flow process (Fig 8) will be operated concurrently with the Jodavis operations. In this process shale crushed to small size will pass continuously downward between two sets of louvers. Hot gases will be driven transversely across the downward-moving bed to retort the shale, and the spent shale will be withdrawn continuously from the bottom of the unit. It is believed that the Gas-Flow process will show good prospects for larger developments in that it can handle large tonnages at a modest construction outlay; it can produce considerable quantities of high calorific gases for other plant uses; and it can be self-sustained thermally by using the spent shale as fuel for heating the hot gases for the process.

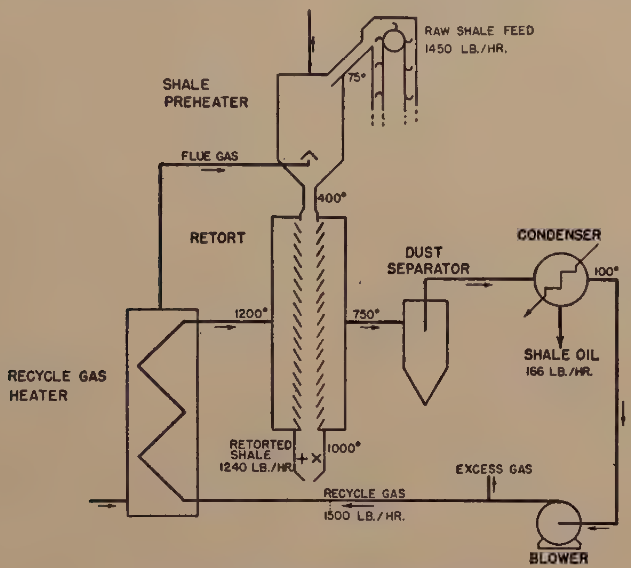

FIG 8—GAS-FLOW PROCESS PILOT PLANT.

Refining

In developing shale-oil refining processes experimental pilot-plant work will be carried out in the engineering development unit at Rifle simultaneously with the retorting work. Laboratory studies are being made at the Laramie research station on several processes, and data from this work soon will be available to begin the engineering and design work for erecting pilot-plant refining units at Rifle. The studies now under way include thermal and catalytic cracking, hydrogenation, desulphurization and related work, such as emulsion breaking, solvent extraction, and other processes widely used in the petroleum industry, but these will require modification and new approaches and techniques for application to shale-oil refining.

COOPERATIVE PROGRAM

A program of cooperative work has been instituted and is now progressing between the Bureau of Mines, the industry, the armed forces, other Government agencies, and educational and industrial research organizations. It is felt that the cooperative work is of primary importance in the overall oil-shale program, since the solution of the many problems connected with developing and establishing a functioning oil-shale industry must come as a cooperative effort. In this program the Bureau of

Mines has enjoyed the particular interest and assistance of the various groups. To date the work performed in operating equipment and processes belonging to others, but made available to the Bureau, has been very helpful. Other experimental work using large-scale equipment constructed or modified for oil-shale work now is being negotiated with several major petroleum refiners. The large sums of money being expended by these companies in adapting their equipment for the oil-shale work offers some indication of their interest and expectations.

At present the Bureau of Mines is maintaining a large file of those requesting information or samples of oil shale and shale oil for cooperative investigations. Its policy is to provide samples to all who wish to participate in the work, providing, of course, that complete results of the work are exchanged on a nonconfidential basis.

Duration of the Oil-shale Program

Under the provisions of the Enabling Act, Public Law 290, 78th Congress, the program was intended to extend over a period of five years, which will expire July 1, 1949. Owing to the magnitude of the work and the difficulties met during the troubled past three years, it has been necessary to request the Congress to grant an extension of three years to the program. This extension bill is now pending in Congress.

Summary

The oil-shale program is nearing completion of the initial construction phase to provide facilities for prosecuting the experimental demonstration plant work at Rifle. Two 40-ton oil-shale retorts are in operation, two pilot-plant retorts will be operating soon, and a plant-scale refinery is being erected. A program of cooperative work in oil-shale experimentation with the industry, the armed forces, and research organizations is going forward with increasing speed toward a mutual solution of the problems that will hasten the development of techniques and processes for the economical processing of oil shale.

When the first five-year period ends, the solution of some of the problems will have been found, but much additional work must be finished before the task can be completed finally. Passage of the extension bill will make it possible to complete the tasks that otherwise would remain half-finished at high cost in money and effort.

When the program is completed the Bureau of Mines expects to have developed techniques and full-scale processes for low-cost utilization of oil shale through all phases of mining, retorting and refining and to make available to industry these processes and techniques for use in developing the oil-shale resources of the Nation.

Chapter III. *Research*

Some Results of Gas and Water Drives on a Long Core

By C. R. Holmgren,* Junior Member AIME

(Tulsa Meeting, October 1947)

Abstract

A large consolidated sand core was used in this investigation. Four groups of experiments including gas drives, water drives, and water drives combined with gas injection, were made.

The results of the gas-drive experiments indicate that greater ultimate recovery may be obtained by higher pressure gradients. However, other considerations challenge the absolute veracity of this conclusion. Results indicate that with connate water present and a low pressure gradient during a gas drive, less gas is required to produce a given amount of oil. The saturation gradient determined during a gas drive is presented.

Results of the water-drive experiments indicate that the recovery of oil is not a function of either gradient or input rate. The presence of initial gas saturation resulted in a slightly lower final oil saturation. Injection of sufficient gas to maintain the initial gas saturation during a water drive resulted in lower final oil saturation.

Introduction

With the demand for petroleum products reaching an all-time record high and the location and exploitation of new reserves becoming more difficult and expensive, the oil industry must look to more thorough and efficient methods of producing the petroleum already located.

Much of the previous work along these lines is exploratory and suggests a more complete investigation. For example, a great amount of laboratory work has been done on flooding sands initially saturated 100 pct with oil. Since sands saturated 100 pct with oil rarely, if ever, exist in nature, and because the water content is a vital factor in the ultimate recovery from the sand, laboratory investigations on cores without water must be supplemented by comparable work on cores with water present.[1,2]

Other investigators have done a considerable amount of laboratory work using gas and water drives.[3] Krutter and Day[4] have reported results of investigations using cores saturated 100 pct with oil and have concluded that "the ultimate recovery obtained, using air drive, from a completely oil-saturated core depends on the pressure gradients used. The higher the pressure gradient, the greater will be the recovery until a certain pressure range is reached above which the reward of increased recovery is much smaller for similar increments in pressure."

Yuster and Day[5] conclude that less gas and less time are required to produce a given quantity of oil at high pressure gradients than at low pressure gradients; they also conclude that an increase in the viscosity of the oil requires a proportionate increase in the gas needed for recovery. Their results indicate that the gas required to produce a given quantity of oil is greatly reduced by the presence of connate water.

R. C. Earlougher[2] concluded, based on results of water-flooding a large number of

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* Research Dept., Stanolind Oil and Gas Co., Tulsa, Okla.

[1] References are at the end of the paper.

samples from cores, that "economic recovery efficiency by flooding is largely dependent upon two factors; namely, percentage of oil saturation at the beginning of the flood and the velocity of the flooding water."

Morse and Yuster[6] conclude that "with the materials used there is no measurable effect of flooding gradients or velocities upon residual oil saturations attained by water flooding." They also state that the physical and chemical characteristics of the sand and oil have a substantial effect on the recoveries by water flooding.

A number of limitations must be kept in mind during a study of the data and its

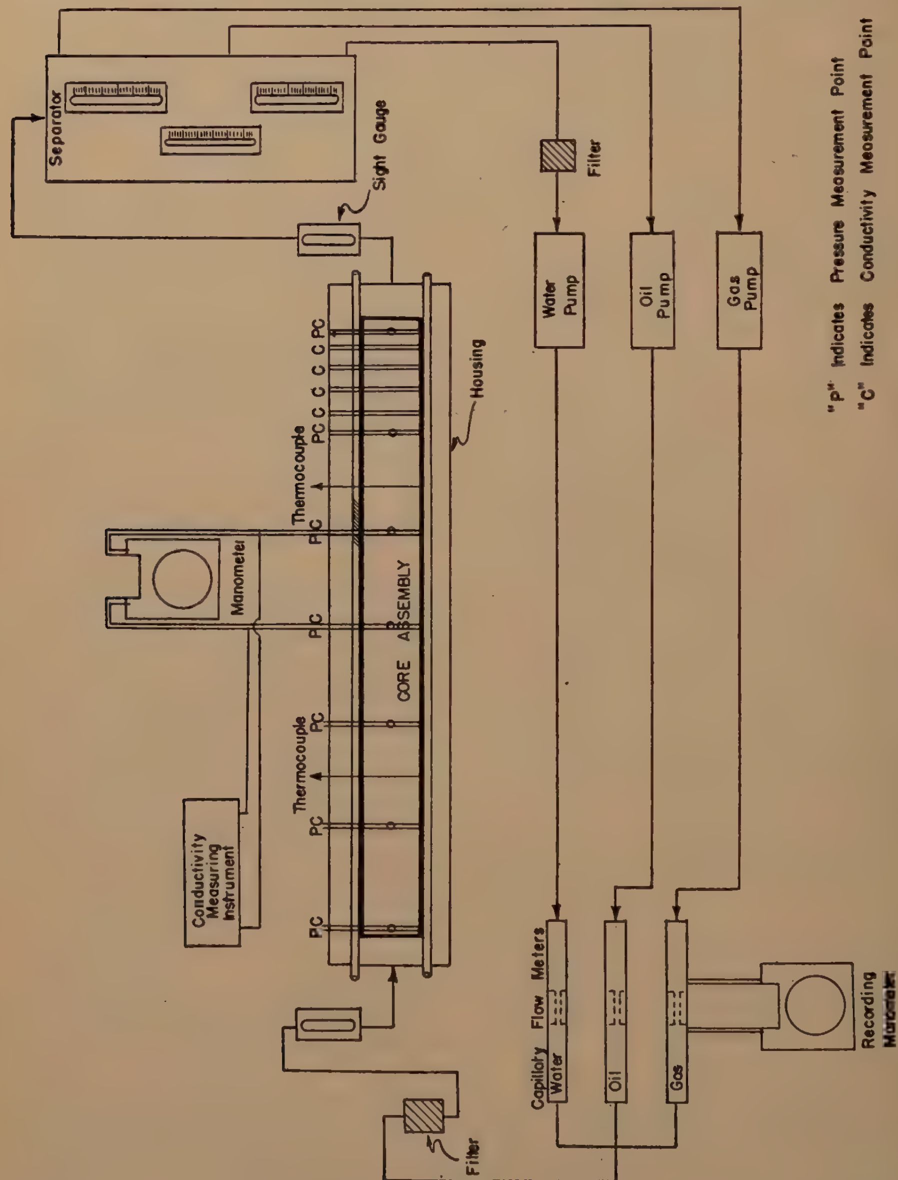

FIG 1—SCHEMATIC DRAWING OF APPARATUS.

application to field problems. Among these are the effects of vertical segregations of fluids in the core, the effect of saturation gradient, and the path of travel of the gas. Springs, Okla., and ground to a cylindrical shape. The core was acidized with hydrochloric acid to remove iron compounds, flushed and dried before mounting. This

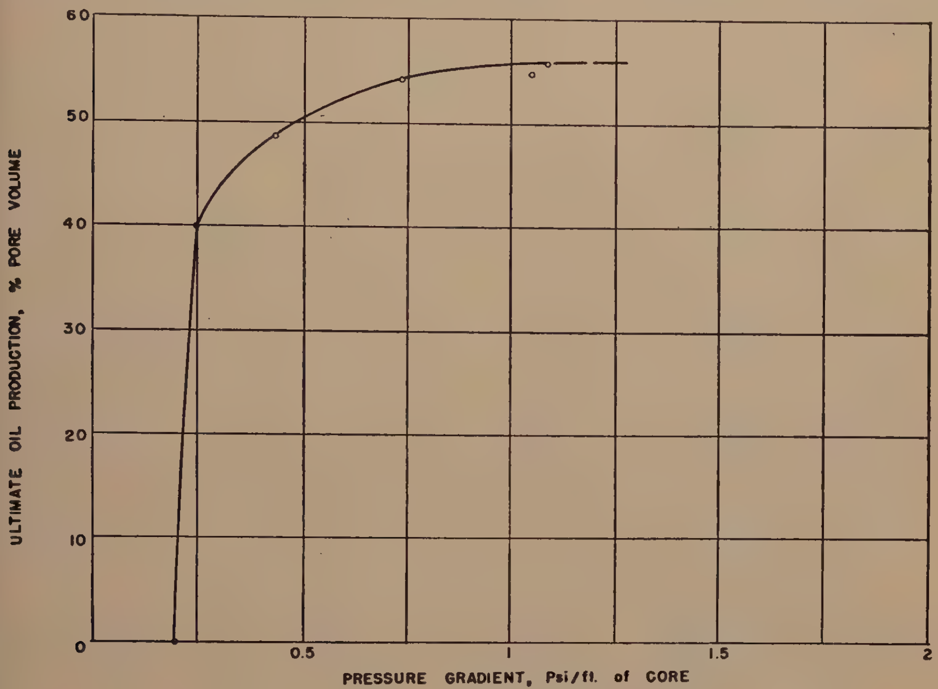

FIG 2—GROUP 1: GAS-DRIVE EXPERIMENTS.

The investigation covered by this paper can be divided into four groups as follows:

Group 1—Five air drives, each with a relatively constant pressure gradient over the length of the core.

Group 2—Five continuous water drives with relatively constant input rate for each drive.

Group 3—Five continuous water drives with relatively constant input rate for each drive and original gas saturation of approximately 15 pct.

Group 4—Two continuous water drives with sufficient gas injection to maintain a constant gas-saturation value.

APPARATUS AND MATERIALS

The core used in this investigation was 5⅞ in. in diameter and 6 ft long. It was quarried from an outcrop near Sand sandstone, which is known as Nellie Bly, is well consolidated and has an average porosity of 27.1 pct and a specific permeability to water of 1660 millidarcys.

Piezometer rings made of brass cups and tubing were placed on the core at one-foot intervals. End plates, thermocouples and conductivity rings were attached, and the entire assembly sealed in Catalin plastic. This assembly was then mounted in a heavy steel housing.

Fig 1 shows a schematic diagram of the apparatus which consists of the core assembly, a liquid-gas separator, individual pumps for water, oil, and gas, capillary flowmeters with recording manometers for each phase, an inlet filter, and suitable inlet and outlet sight gauges. Means were provided to record differential pressure across spaced intervals of the core

through suitable piezometer rings. These rings also served as electrical contacts for measuring the conductivity between core entire apparatus was designed to operate at pressures up to 1000 psi and temperatures up to 150°F.

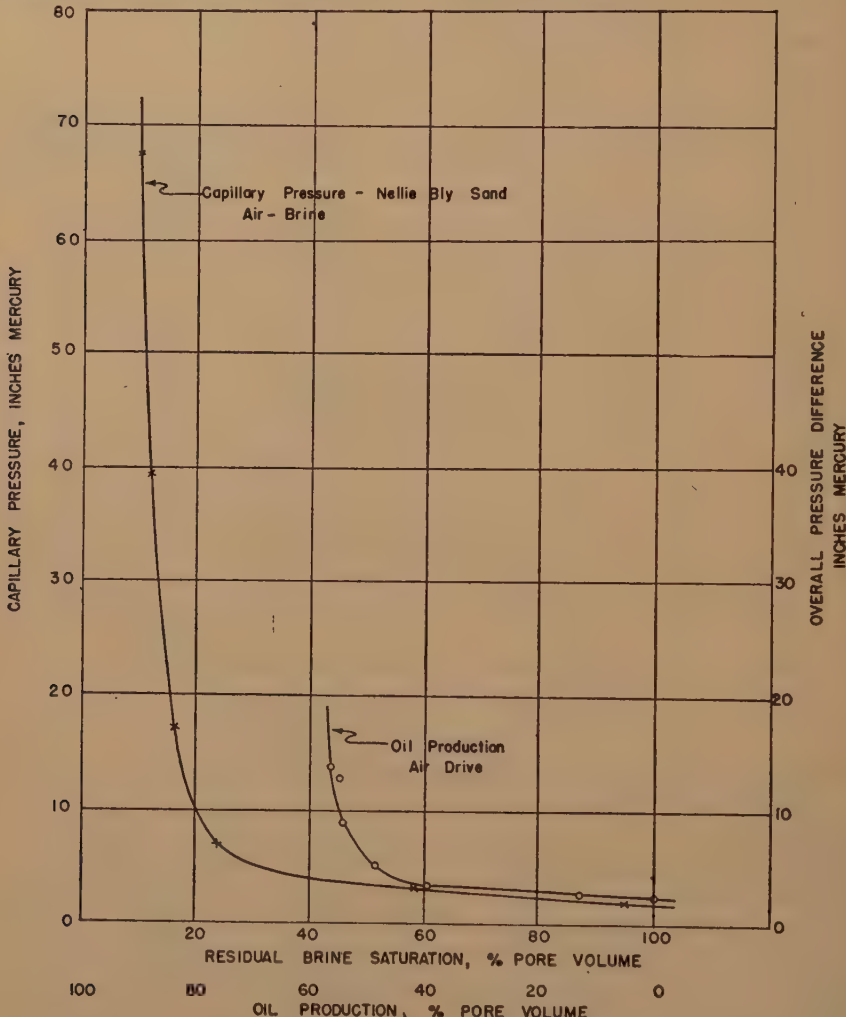

FIG 3—CAPILLARY PRESSURE AND OIL PRODUCTION BY AIR DRIVE.

intervals, which was interpreted in terms of percentage of brine saturation.

Total mass in the core was measured by means of gamma rays. Knowing the portion of total mass represented by brine saturation from the conductivity measurement, oil saturation could be estimated. The mass of the gas was neglected since at the low pressures utilized it was very small. The

The oil used in these experiments was a C_{10}–C_{12} cut with an API gravity of 53.5 at 60°F and a viscosity of 1.61 centistokes at 100°F. This oil is produced commercially by Phillips Petroleum Co. and sold under the trade name "Soltrol-140."

The water was a prepared brine having approximately 33,000 ppm NaCl. Sodium nitrite was added to inhibit corrosion and

sodium phosphate was used to adjust the pH value to about 7.7. Air was used as the gas for these experiments.

Krutter and Day[4] state that "no appreciable difference was found in recovery when methane was used than when air was used as the driving medium. Also, the relative permeability to methane as a function of oil saturation was the same as that for air."

TABLE—1. *Group 1: Gas Drives—Gas Requirements*

Pore Volumes of Gas Passed through Core	Drive Number..	1*A*	1*B*	1*C*	1*D*	2
	Pressure Gradient, Psi per Ft.	1.04	0.73	0.43	0.25	1.08
	Water Saturation, Pct......	19.2	17.9	17.9	17.9	19.1
	Oil Production in Percentage of Pore Volume					
1		8.5	10.5	7.9	8.9	10.0
5		17.5	19.4	19.7	21.1	18.2
10		22.0	24.5	25.7	27.1	23.6
22.8		28.0	31.3	33.0	34.7	29.3
50		35.9	38.3	40.7		35.7
100		44.2	45.1	47.0		42.0
123		45.9	46.4	48.8		43.1
200		46.2	50.5			47.5
300		52.9	52.8			50.3
391		54.4	53.8			51.8
402			54.3			51.9
842						55.7

The outlet pressure in all experiments was atmospheric. All experiments were made at room temperature of about 80°F, and all conductivity measurements were referred to 80°F for comparison. Consequently, errors introduced by viscosity changes caused by pressure and temperature differences would be negligible.

The core was saturated by evacuating from both ends and then permitting liquid from an outside source to flow into one end while evacuation continued from the other end. After the saturating liquid appeared at the end being evacuated, each end of the core was again evacuated and pressured with the liquid several times.

Tests in which additional oil was forced into the core at pressures of about 50 psi and also in which oil was circulated under pressure indicated that total liquid saturations of 98 to 100 pct were achieved by this method.

EXPERIMENTAL RESULTS

Group 1. Air Drive at Constant Pressure Gradient

The objective of this group of five air drives was to determine the effects of pressure gradient upon ultimate recovery, the volumes of air required to produce these recoveries, and the effect of intermittent injection. The drives numbered 1*A*, 1*B*, 1*C*, 1*D* were continuous, and drive No. 2 was intermittent.

In all drives of this group, the core initially contained water ranging from 17.9 to 19.2 pct of the pore volumes, with the remainder of the pore volume filled with oil. The air-input pressure was maintained at as constant a value as possible. The effect of pressure gradient on oil production in these gas drives is shown in Fig 2.

The air-brine capillary-pressure curve for the Nellie Bly sand is shown in Fig 3, together with the curve showing oil production against pressure difference for the drives. The two curves are very nearly parallel, with good agreement at the lower pressures.

The results of this group of air drives indicate that greater ultimate recovery was achieved by application of a greater pressure gradient. This effect was much more pronounced at low gradients and soon reached a point where a large gradient change produced only a very small saturation change. However, since it is known that a saturation gradient, with a piling-up effect at the outlet, exists in the core, and good agreement is obtained between the gas-drive production curve and capillary-pressure curve at low pressure differentials, it is very possible that the gain in production was actually caused by two capillary effects. These cause a slight reduction in oil saturation over a large portion of the length of the core and a variation in the

end effect. Combined they show increased oil production.

During drive No. 2 the air was injected for 8 hr per day with shut-in periods from 16 to 60 hr between injections. Intermittent injection appeared to have little or no effect on ultimate recovery, but the gas requirement was approximately double that of the comparable continuous run, 1*A*, at the end point, and appeared to increase after about 50 pore volumes had been passed through the core.

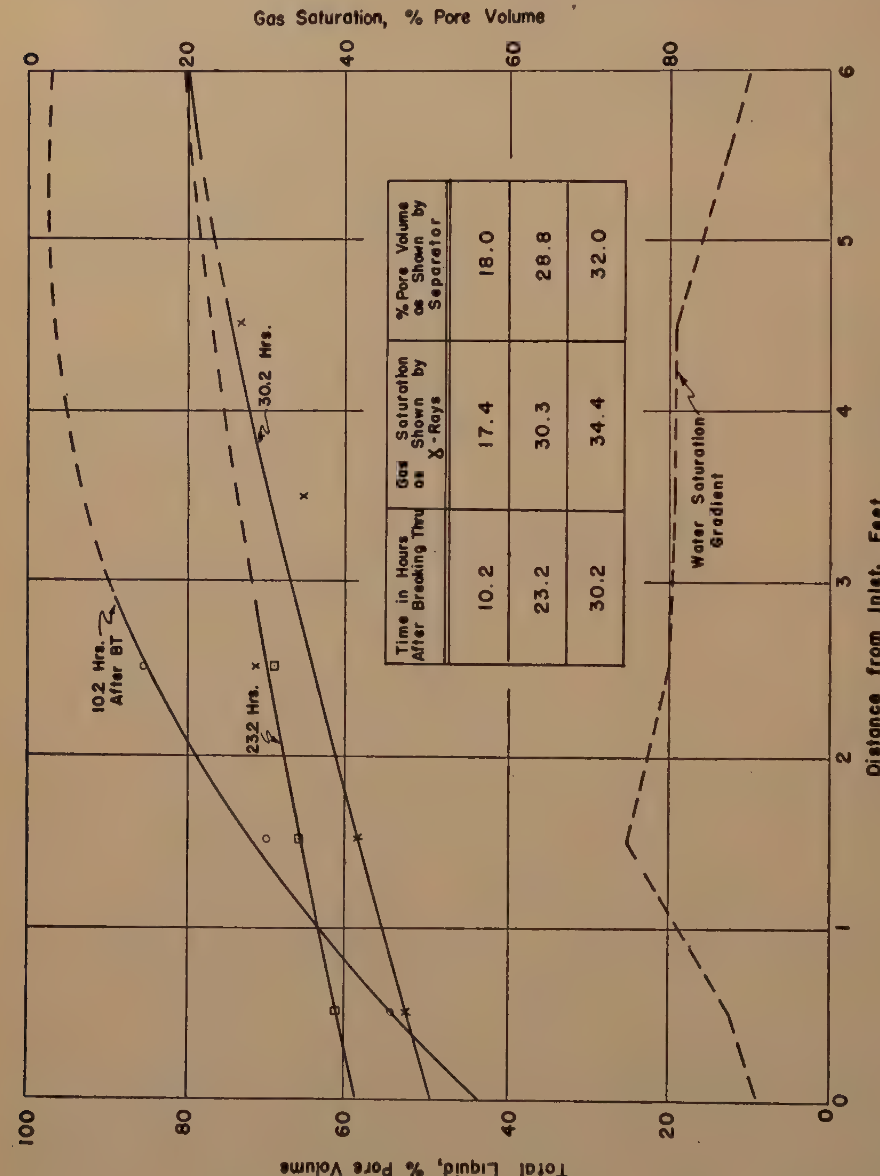

Fig 4—Fluid gradient during gas drive.

Gas requirements for the Group 1 drives are shown in Table 1. Pore volumes as

shown are at atmospheric pressure and 80°F.

Considering only the continuous drives and the data up to the passage of 200 pore volumes of gas through the core, the results of the Group 1 drives indicate that with lower pressure gradients less gas is required to produce a given quantity of oil. After saturation becomes great enough so that the drive gradient is not sufficient to overcome the capillary forces, no more oil will be produced, and the gas-oil ratio will approach infinity.

In all drives, the outlet sight glass was carefully watched for gas breakthrough, and a separator reading was made when it occurred. Oil production at the time of breakthrough varied from 2.80 to 3.94 pct of the pore volume with an average for 11 observations of 3.42 pct. Assuming a maximum of 2 pct original gas saturation, these results indicate that the equilibrium gas saturation, or the saturation at which gas flow will begin, for this core, is probably nearer 5 pct than the 10 to 11 pct usually accepted.[7]

Gas drive No. 1*D* was begun with a very low pressure gradient. No measurable oil production was obtained until the pressure gradient was increased to 0.19 psi per foot of core. Gamma-ray logs were made almost continuously during this drive for the purpose of determining the saturation gradient along the core after gas appeared at the outlet. The results obtained are shown in Fig 4. Difficulty encountered in reproducing data from the stations in the outlet half of the core made interpolation necessary. A comparison of average gas saturation as estimated by the interpolated curves and as indicated by separator readings is given in the table of Fig 4.

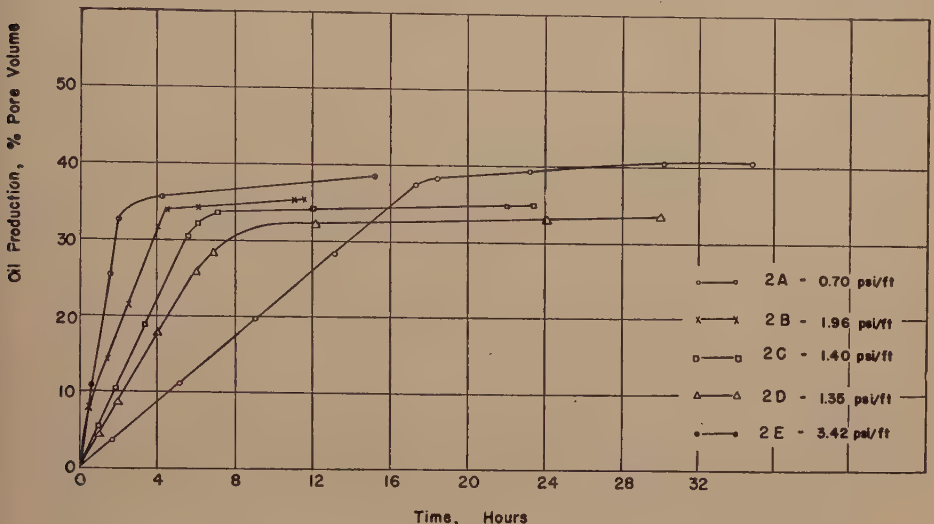

FIG 5—WATER-DRIVE EXPERIMENTS—GROUP 2: OIL PRODUCTION AGAINST TIME.

Group 2. Continuous Water Drive with Low Gas Saturation

In this group of five water drives, the initial water saturations in all cases was from 20.2 to 26.8 pct. The remainder of pore volume was saturated with oil up to a total liquid saturation of 98 to 100 pct. Input rates ranged from 3.76 to 26.0 cc per min., with pressure gradients from 0.70 to 3.42 psi per ft of core being developed. These drives are numbered 2*A*, 2*B*, 2*C*, 2*D*, and 2*E*.

The average water saturations when the

efflux was 100 pct water were equal, within experimental limits, regardless of the input rate, gradient developed, or the initial water saturation. Consequently, the amount

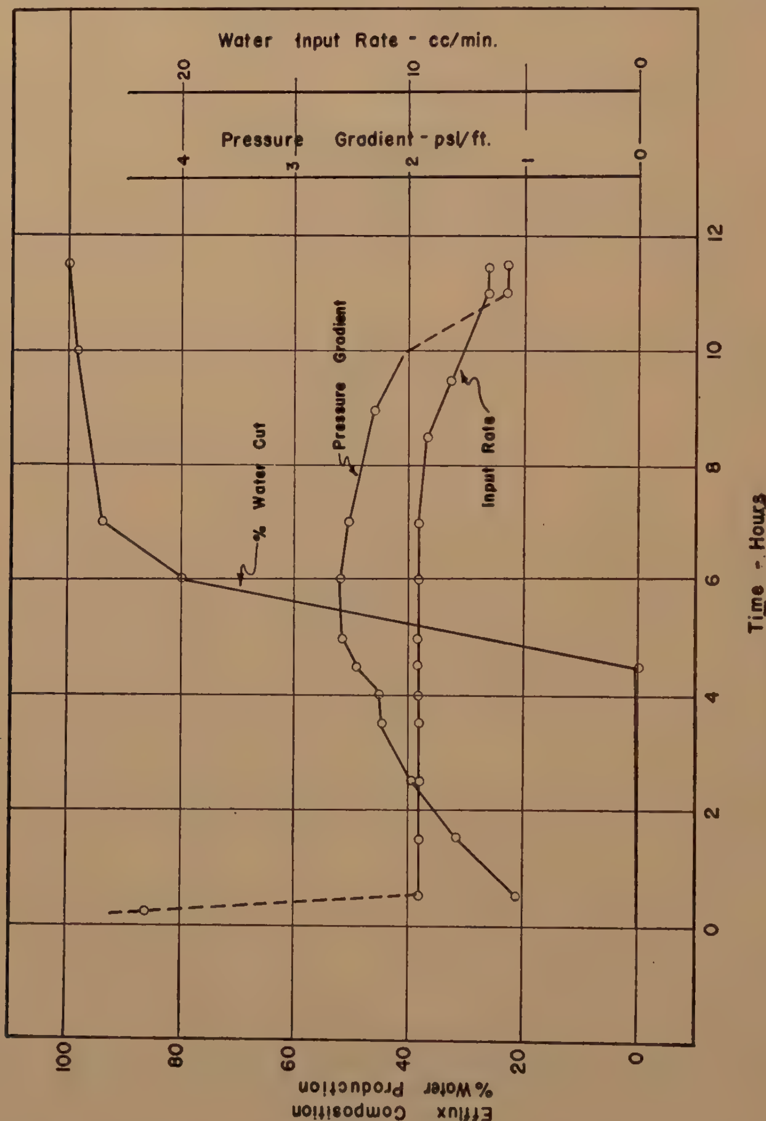

Fig 6—Water-drive experiment no. 2*B*: typical data.

of oil produced by the drive was nearly equal to the difference between the original and final water saturations. The recovery of oil was not a function of either gradient or input rate.

Production was very definitely divided into two phases;[8] the "initial" phase, in which the displacement of oil was very efficient and the water saturation rose rapidly, and the "subordinate" phase, in which little additional oil was produced and the water saturation changed slowly.

The breakthrough, or point at which production changed from oil to water, was defi-

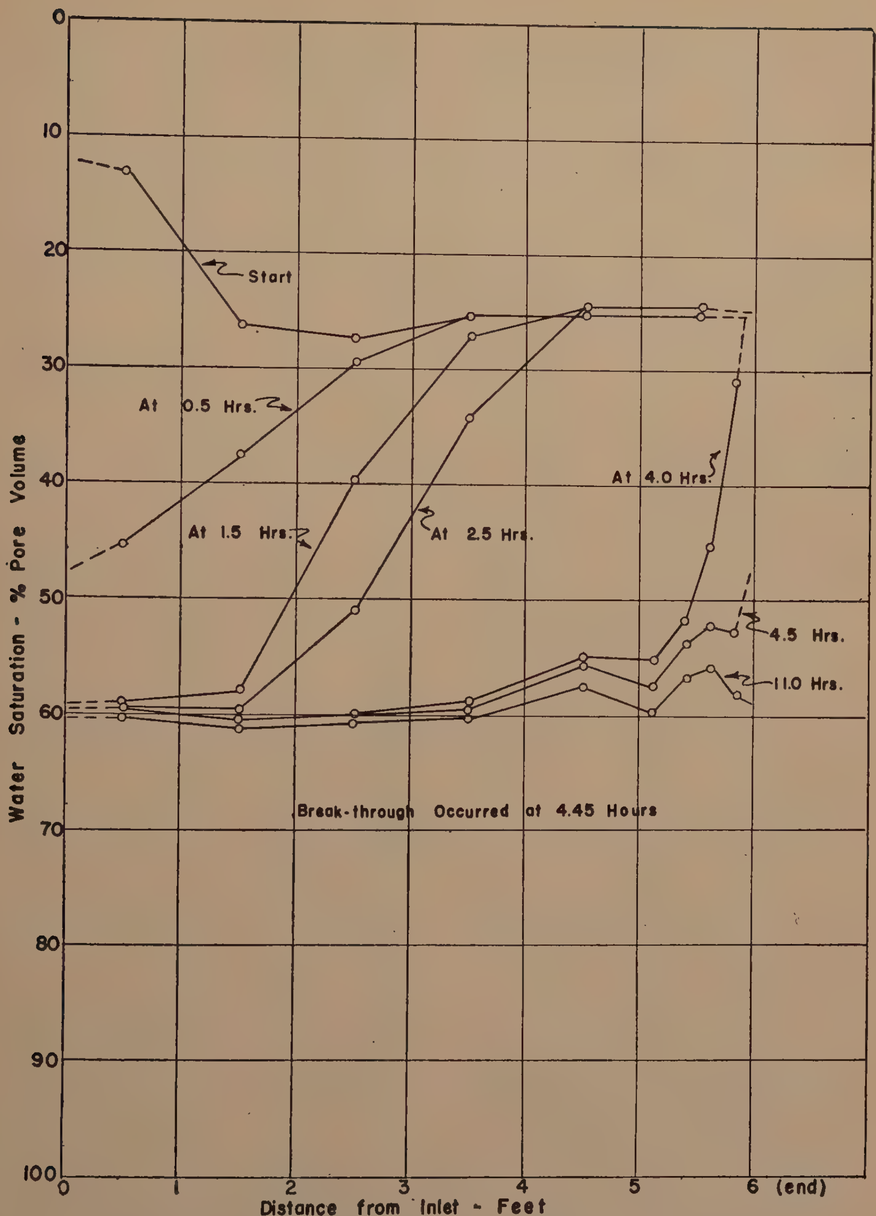

FIG 7—WATER-DRIVE EXPERIMENT NO. $2B$: SATURATION GRADIENTS.

nite and clean-cut, and only a small amount of oil was produced after breakthrough.

The results of these drives are shown in Fig 5. The data obtained in a typical drive, $2B$, are shown in Figs 6 and 7. Fig 7 shows the progress of the drive as reflected by the water saturation in various sections of the core at specified times. Data obtained in these drives are given in Tables 2 and 3. Table 3 illustrates the water-saturation

conditions, foot by foot, at the start of the drive, at breakthrough, and at the point where the efflux was 100 pct water.

TABLE 2—*Group 2: Water Drives—Low Initial Gas Saturation*

GENERAL DATA

Drive number	2A	2B	2C	2D	2E
Pressure gradient Psi per ft of core	0.70	1.96	1.40	1.35	3.42
Water-input rate, cc per min	3.76	9.38	7.82	6.95	26.0
Lin. ft per day	6.24	15.57	12.98	11.54	43.17
Original water saturation, pore volume, pct	20.2	23.5	23.7	26.8	24.5
Original oil saturation, pore volume, pct	79.8	75.8	75.5	72.3	74.3
Final water saturation, pore volume, pct	60.8	59.7	59.5	59.1	60.2
Residual oil saturation, pore volume, pct	39.1	40.3	40.7	38.7	37.6
Oil recovery, pore volume, pct	40.7	35.5	34.8	33.6	36.7
Oil recovery, original oil in place, pct	51.0	46.8	46.1	46.5	49.4
Drive time to completion, hr	30.25	11.0	20.0	22.0	13.25
	Average residual oil, 39.3 pct				

TABLE 3—*Group 2: Water Drives—Low Initial Gas Saturation*

WATER-SATURATION DATA, CORE SECTION

Drive Number	First Foot	Second Foot	Third Foot	Fourth Foot	Fifth Foot	Sixth Foot	Average
At Start of Drive							
2A	14.5	22.2	22.7	20.6	19.4	28.1	20.2
2B	13.0	26.3	27.2	25.1	25.1	25.1	23.5
2C	23.1	30.8	28.0	23.1	20.4	17.0	23.7
2D	18.9	32.3	31.6	27.1	25.8	24.9	26.8
2E	17.9	27.1	27.9	25.2	24.1	24.1	24.5
At Water Breakthrough							
2A*	60.4	61.1	61.0	60.3	56.3	50.6*	58.3
2B	59.8	60.5	59.9	59.3	55.6	54.7	58.3
2C	57.6	59.7	60.0	59.3	55.8	53.7	57.8
2D	57.1	59.0	59.5	58.7	54.9	53.0	57.0
2E	58.7	59.9	60.0	58.9	55.7	54.2	58.0
At Time Efflux is 100 Per Cent Water							
2A	61.6	61.2	62.7	61.5	58.6	59.0	60.8
2B	60.3	61.2	60.8	60.3	57.5	58.0	59.7
2C	58.6	60.6	61.1	60.4	57.9	58.4	59.5
2D	58.6	59.9	60.7	60.2	57.2	58.1	59.1
2E	59.9	61.2	61.7	60.3	58.7	59.4	60.2
Average	59.8	60.8	61.4	60.5	58.0	58.6	59.9

* At 17.25 hr., breakthrough at 18.42 hr.

In field practice the flow rate, or the advance of water, is generally expressed in linear feet per day. To convert input rates in cubic centimeters per minute to linear feet per day it is necessary to determine or estimate the fraction of the pore volume available for water flow. Figures given in the tables are based on an estimate of 60 pct of the pore volume being effective. For this core, the following formula may be used for the conversion if rates based on a value other than 60 pct are desired:

$$F = \frac{0.9962\,R}{V}$$

Where:

F is flow rate in lin. ft per day

R is input rate in cc per min.

V is the fraction of pore volume effected

TABLE 4—*Group 3: Water Drives—High Initial Gas Saturation*

GENERAL DATA

Drive Number	2F	2G	2H	2J	2K
Pressure gradient, Psi per ft of core	2.56	1.96	2.53	1.20	2.89
Water-input rate, cc per min	7.2	3.82	6.98	3.71	11.5
Lin. ft per day	11.95	6.34	11.59	6.16	19.09
Original water saturation, pore volume, pct	23.5	26.1	25.9	26.4	26.4
Original gas saturation, pore volume, pct	15.4	15.2	14.7	15.5	14.6
Original oil saturatino, pore volume, pct	61.1	58.7	59.4	58.1	59.0
Final water saturation, pore volume, pct	57.6	54.7	59.2	53.9	55.7
Final gas saturation, pore volume, pct	5.5	7.4	6.3	8.7	1.5
Residual oil saturation, pore volume, pct	36.9	37.9	34.5	37.4	42.8
Oil production, pore volume, pct	24.2	20.8	24.9	20.7	16.2
Oil production, original oil, pct	39.6	35.4	41.9	35.6	27.5
Drive time to completion, hr	20	25	25.25	28.25	14.5
	Average residual oil, 37.9 pct				

Fig 8 is a plot of data from Group 2 involving time, in that input rates are converted to pore volumes and plotted against percentage of ultimate oil recovery.

Group 3. Continuous Water Drive with High Initial Gas Saturation

In this group of five drives, 2F, 2G, 2H, 2J, and 2K, the initial gas saturation was

about 15 pct of the pore volume. This condition might be compared to a reservoir after gas-expansion production. Initial gas gas saturation was attained, and then the direction of gas flow was reversed until the desired initial gas saturation was reached.

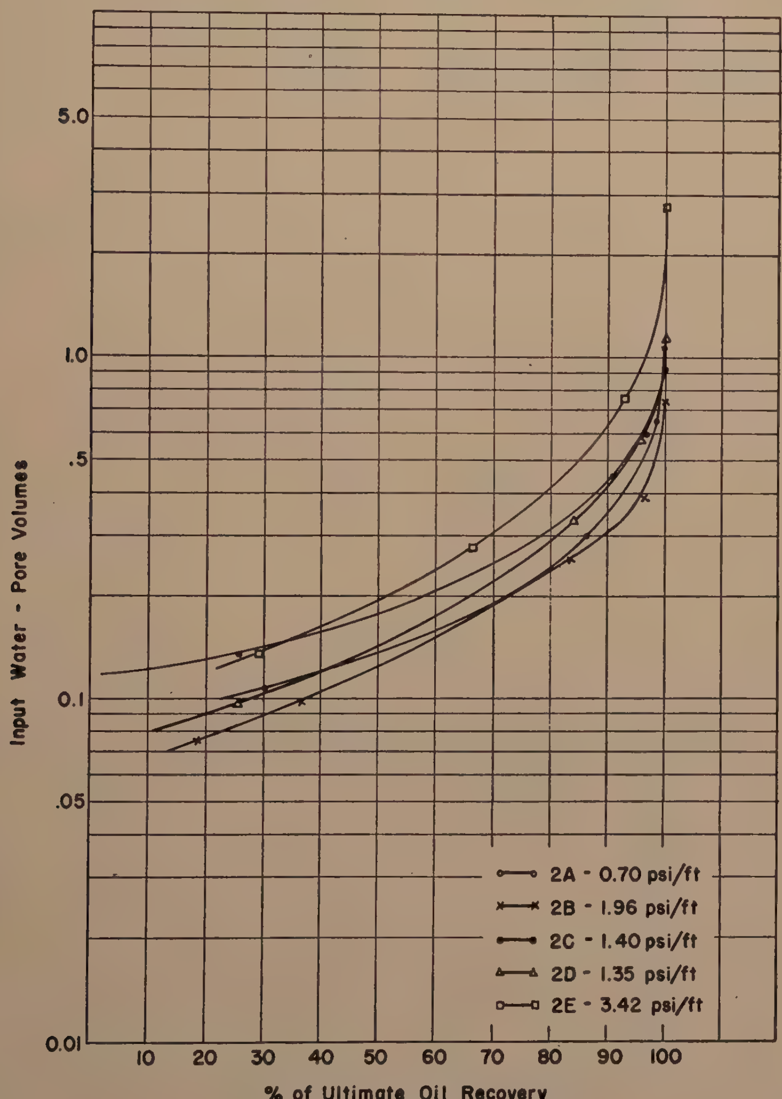

FIG 8—WATER-DRIVE EXPERIMENTS—GROUP 2: ULTIMATE OIL RECOVERY AGAINST INPUT WATER VOLUME.

saturation was calculated by measuring oil produced from the fully saturated core by gas drive. The drive was made from one end of the core until 60 to 70 pct of the desired By this method, the total liquid saturation gradient should be quite uniform along the core. The data for these drives are given in Table 4.

Again, in Group 3, the variation in the input rates did not establish a trend in the oil production, although the average residual oil obtained was slightly less than in Group 2. The final gas saturations varied inversely as the pressure gradient developed. Higher pressure gradients were developed in Group 3 than in Group 2 for comparable flow rates.

No oil was produced during these drives until the average gas saturation had been reduced to near the final gas saturation by

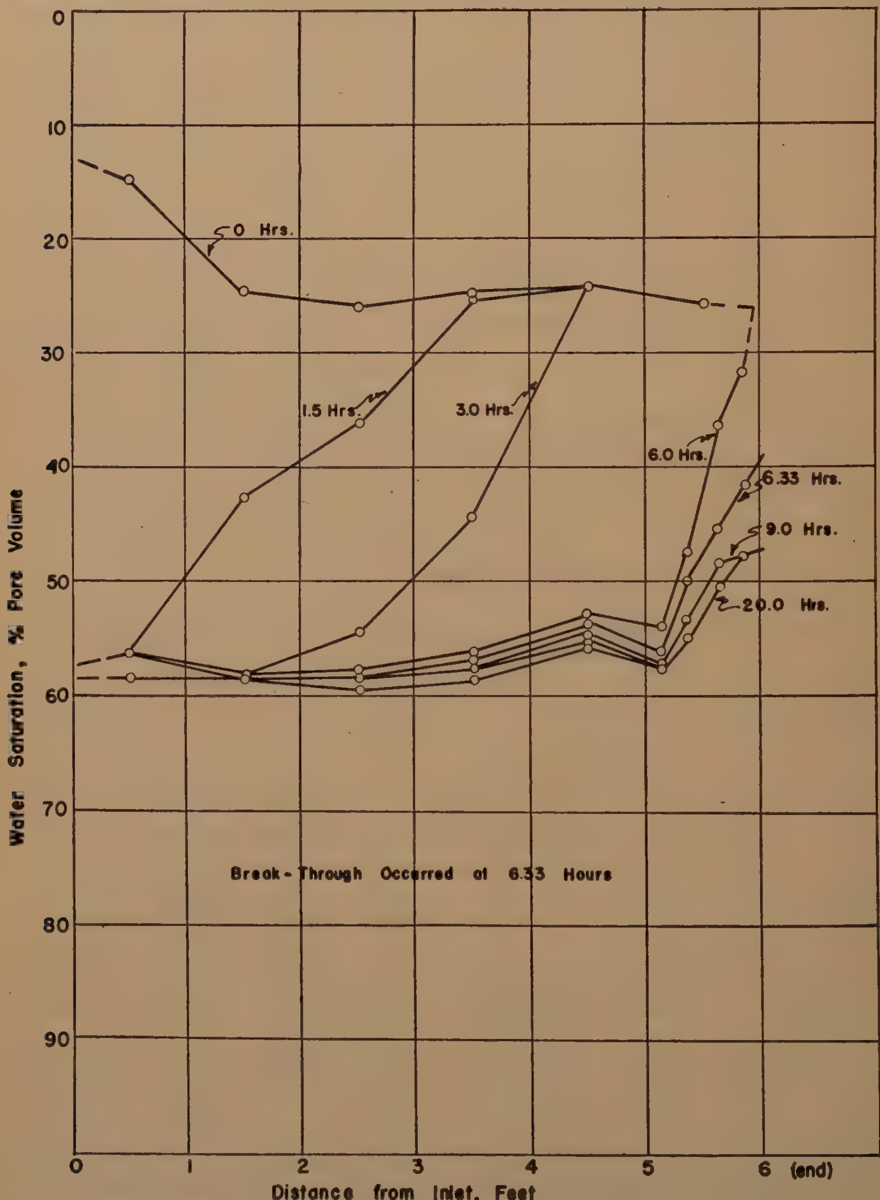

FIG 9—WATER-DRIVE EXPERIMENT 2*F*—GROUP 3: SATURATION GRADIENTS.

pumping in an appreciable amount of water. The results of a typical drive, *2F*, given in Table 5, clearly illustrate this point. Gas production was observed at the outlet during the early stages of each drive, but had diminished to zero by the time the final gas saturation had been attained. In other words, no oil was produced until sufficient water had been injected to reduce the gas saturation to a point where the permeability to gas was practically nil. At the same time, the injected water did not affect the water saturation of any of the sections ahead of the water front. This is illustrated by the results as shown in Fig 9.

TABLE 5—*Group 3: Water Drives—High Initial Gas Saturation*

DATA FOR DRIVE NUMBER 2F

Time during Drive, Hr	Water Saturation, Pore Volume, Pct	Change in Water Sat., Pore Volume, Pct	Oil Production, Pore Volume, Pct	Gas Saturation, Pore Volume, Pct	Change in Gas Sat., Pore Volume, Pct	Remarks
0	23.5	0	0	15.4		Start
1.5	34.9	11.4	2.5	6.5	8.9	
3.0	44.4	20.9	9.3	3.8	11.6	
5.0	51.2	27.7	16.6	4.3	11.1	
6.33	55.5	32.0	21.1	4.5	10.9	Water Breakthrough
13.0	56.5	33.0	24.0	6.4	9.0	
20.0	57.6	34.1	24.2	5.5	9.9	End

Group 4. Continuous Water Drive together with Air Injection Sufficient to Maintain Relatively Constant High Gas Saturation

The results of Group 2 indicate maximum water saturation that can be attained by water flooding in this core, and Group 3 indicates that the initial gas saturation is largely replaced by liquid during a water drive without appreciable change in residual oil. Therefore, if the initial gas saturation could be maintained, and the maximum water saturation achieved, the residual oil should be at a minimum. Two drives, *2L* and *2N*, were made with gas injected together with water. Flow rates for both water and gas were adjusted from time to time to hold the average gas saturation as close to the initial value as possible. Although the initial gas saturation was not maintained exactly, and water saturation did not reach as high a value as in the other groups, the residual oil saturation was lower. The results of these drives are given in Table 6.

TABLE 6—*Group 4: Water Drives with Gas Injection*

GENERAL DATA

Drive number	*2L*	*2N*
Original water saturation, pore volume, pct	25.8	21.8
Original gas saturation, pore volume, pct	14.3	19.4
Original oil saturation, pore volume, pct	59.9	58.8
Final water saturation, pore volume, pct	54.1	47.7
Final gas saturation, pore volume, pct	10.4	19.4
Residual oil saturation, pore volume, pct	35.5	32.9
Oil production, pore volume, pct	24.4	25.9
Oil production, original oil, pct	40.7	44.0
Water-input rate, overall average, cc per min	5.08	4.62
Lin. ft per day	8.43	7.67
Overall average pressure gradient, Psi per ft of core	5.55	5.91
Drive time to completion, hr	22.5	26.0
Total gas throughput, pore volumes at outlet	56.2	221.7
Average residual oil, 34.2 pct		

CONCLUSIONS

1. Results of the gas drives indicate that greater ultimate recovery of oil may be obtained by higher pressure gradients, although other considerations indicate that this conclusion might be false when no saturation gradient is present.

2. For the range investigated in a constant-pressure-gradient gas drive, the volume of gas required to produce a given quantity of oil decreases as the pressure gradient decreases when the core contains connate water.

3. For the range investigated, the water-input rate and the resulting pressure gradient during a water drive at low gas saturation has no discernible effect on the final oil saturation of the core.

4. The presence of a relatively high initial gas saturation in the core before water drive results in a slightly lower final oil saturation than when no initial gas is present.

5. Maintenance of initial gas saturation by gas injection, together with an increase in water saturation by water input, results in lower final oil saturation.

Acknowledgments

Acknowledgment is due Messrs. Lincoln F. Elkins, R. L. Whiting, Dr. C. W. Zeimer, and many members of the present staff of the Stanolind Oil and Gas Company's Research Department for their part in the design, construction, and initial calibration and testing of the apparatus. The writer thanks the management of Stanolind Oil and Gas Co. for permission to publish this paper.

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DISCUSSION

L. F. Elkins*—Results of laboratory experiments presented in this paper indicate that large increases in gas-sweep volume are necessary to attain a given recovery with an increase in pressure gradient. This increase averages 66 pct for this core with a fourfold increase in pressure gradient with recovery of oil of 20 to 35 pct pore volume. Such results are of considerable importance if similar behavior occurs in oil reservoirs. The pressure gradients in the laboratory tests ranged from 0.25 to 1.04 psi per foot, while average datum pressure gradients between areas of gas injection and the area of oil production ranged from 0.01 to 0.08 psi per foot for four gas-injection projects with which I am familiar. Thus test pressure gradients are some three to one hundred times greater than those existing in these four gas-drive projects. In each of these gas is being injected into structurally high wells and oil produced from lower wells, but pressure gradients exceed the available gravity head of oil.

Pore volumes of gas at various recoveries of oil interpolated from Table 1 for the continuous gas drives were corrected to average pressure in the core for proper comparison. These are plotted in Fig 10 in various combinations of rectilinear and logarithmic scales to illustrate the uncertainty of extrapolating these test results. Only the semilog plot, Fig 10*b*, with pressure gradient on the linear scale permits linear correlation of data of all four pressure gradients. Presumably this provides the most reliable extrapolation to other ranges of pressure gradient. It indicates an increase of only 2 to 4 pct in gas requirements to attain a given oil recovery with a four-hole increase in pressure gradient within the realm of existing reservoir conditions. This does not prove that pressure gradient and rate of production are unimportant in oil recovery but rather indicates the necessity of extending the experiments to these very low pressure gradients.

In the water-drive experiments, oil recovery of only 2 pct of pore volume was obtained after the water breakthrough. This indicates that flow of one fluid predominates at any one

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point in the core. Wells do not normally show such rapid transition from all oil to all water. However, this does not invalidate the experimental result indicated above when applied to actual reservoirs, but rather indicates that well performance is the composite of a group of zones, streaks, or even individual reservoirs performing concurrently. It does point to the very difficult problem of locating and measuring these individual zones and of determining proper production practice to obtain the maximum economic recovery of oil therefrom.

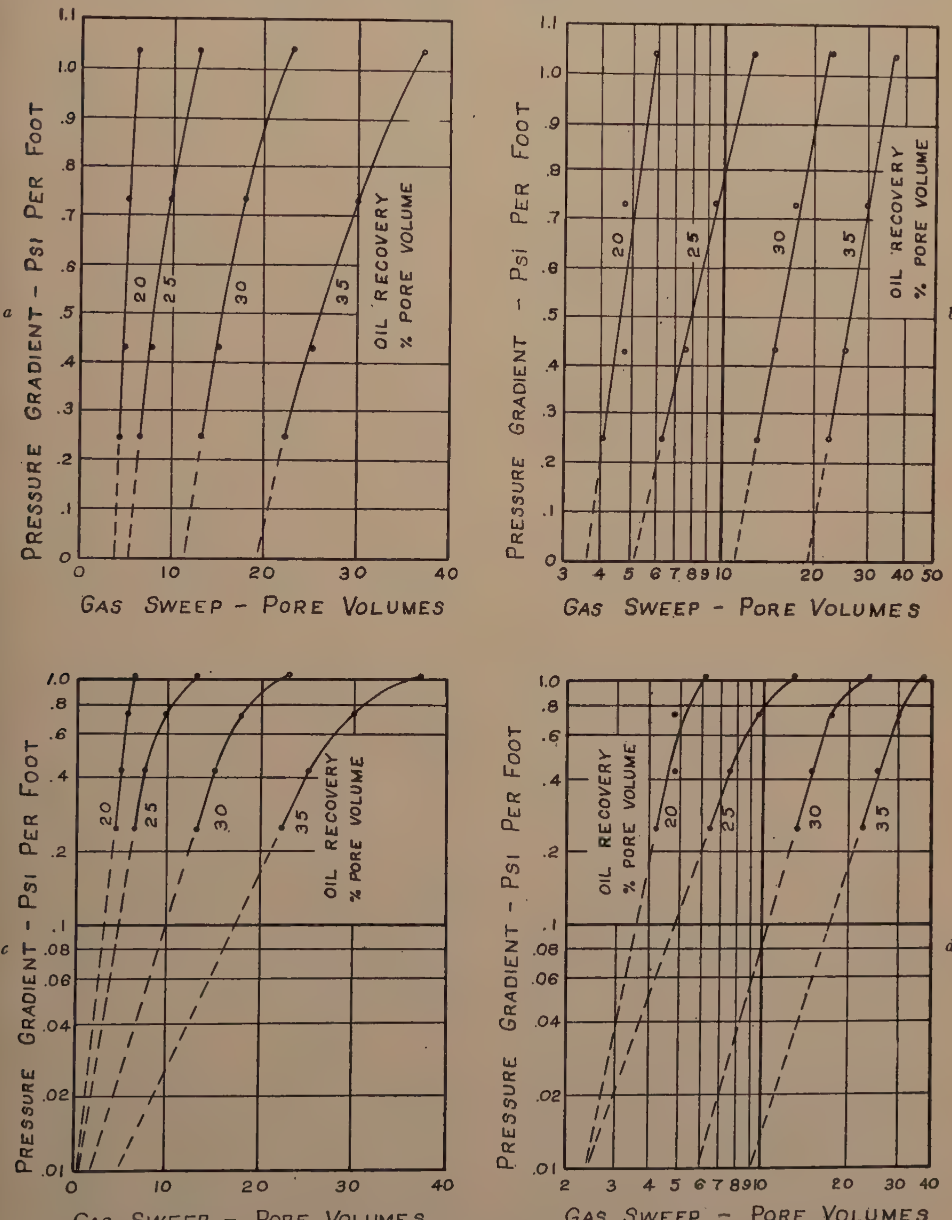

FIG 10—EXTRAPOLATIONS OF EXPERIMENTAL DATA ON GAS SWEEP VS PRESSURE GRADIENT.

E. T. HECK*—The mechanism of the flow of fluids through sandstone is a problem that will not be solved by a few experiments. A great deal of data must be assembled and Holmgren's paper is a valuable contribution. It should be pointed out, however, that a solution of sodium chloride and a close cut oil may give results that cannot be related to field results.

There are just enough basic data given in the paper to raise several questions but not enough to prove that the statements in the text of the paper are fully supported by experimental data. Tables 2 and 4 indicate that the various runs were made at the indicated pressure and input rate. Obviously, one or both of these must be averages of some sort. Fig 6 indicates that the input rate was constant for most of run 2*B* and that the pressure gradient started at about 1 psi per foot, rose to about 2.7 psi per foot, and then declined to about 1.2 psi per foot. It is not clear how the figure of 1.96 psi per foot shown in Table 2 was determined.

Since it is stated that Fig 6 shows "Typical Data," it must be assumed that all of the water drive experiments were run at a given input rate rather than at a given pressure gradient. If this is true the experiments reported in this paper are not directly comparable with any other similar experiments known to this writer. Fig 6 shows that both the input rate and pressure gradient were changed toward the end of the run. If both the input rate and pressure gradient were permitted to vary in the other runs, the data probably cannot be interpreted and the remainder of this discussion and most of Holmgren's statements are meaningless.

Experiments by other investigators indicate that when a piece of sandstone is driven with water and then resaturated with oil without extracting it is rarely if ever possible to reproduce the first run. Subsequent runs, however, can be reproduced. For the purpose of this discussion, it is assumed that the runs reported upon in this paper were carried out in the sequence indicated by the letters. That is, that run 2*B* followed 2*A*, 2*C* followed 2*B*, and so on.

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If run 2*A* is ignored the basic data would seem to be at variance with some of the statements in the text. Fig 5 would seem to show that recovery increased with increase in input rate. In Table 2, the final water saturation increases with increase in input rate. The residual oil saturation decreases as the input rate increases except for run 2*D*, and here the original oil saturation was low. The oil recovery expressed as per cent of pore volume increases with an increase in input rate. The oil recovery expressed as per cent of oil in place increases with an increase in input rate except for 2*D* where the original oil saturation was low.

As might be expected, due to limitations on the accuracy of measurement, the data shown in Table 3 are somewhat erratic. The trend, however, is fairly clear if run 2*A* is ignored. The water saturation increased in all sections with an increase in input rate, both at the water breakthrough point and at the time 100 pct water was produced.

The data in Table 4 do not seem to fall in line. The drive time to completion given for each run raises the question whether all runs were carried to the same end point. Another possibility is that both the pressure gradient and input rate varied during one or more of the runs. If data such as shown in Fig 6 were available for all runs, this discussion might have been more complete. It would be very interesting, and helpful in interpreting the data if the variation in pressure gradient along the core could be shown for various stages in one or more runs.

From Fig 5 and Table 2, it appears that an increase in input rate may yield up to 3 pct of the pore space of additional oil. That is a lot of oil and it is obvious that additional experiments are decidedly worthwhile. It would seem to be desirable to use crude oil, true connate water, and an oxygen free environment if possible, so as to more nearly simulate oil field conditions.

C. R. HOLMGREN (author's reply)—The author appreciates the discussions presented. Obviously all of the data and experience in a project of this nature cannot be included in a single paper. The author recognizes that a great diversity of opinion exists in this field, but feels that the data presented justify the conclusions as they are stated in the paper.

Calculation of Initial Fluid Distributions in Oil Reservoirs

By Morris Muskat,* Member AIME

Abstract

It is pointed out that the application of capillary pressure curves obtained by drainage or desaturation processes to the calculation of the fluid distribution in interphase transition zones involves a number of difficulties; namely: (1) the development of very low nonwetting phase saturations appears to be in contradiction with the lack of mobility of such distributions indicated by permeability-saturation curves, (2) dispersed nonwetting phases are thermodynamically unstable, and (3) discontinuous phases should not be subject to hydrostatic equilibrium requirements. While these difficulties could be obviated by assuming that the capillary pressure drainage curve has an initial horizontal segment, they are automatically circumvented by application of the imbibition capillary pressure curve to the lower part of the water-oil transition zone. These generally show zero displacement pressure at only partial wetting-phase saturations. The countercurrent upward flow of oil into the main oil-saturated pay and downward drainage of water also suggests that wetting-phase imbibition processes will control the saturation distribution immediately above the water-saturated section. Similar considerations, with a generalized interpretation of the apparent wetting-phase behavior of the oil and gas phases, provides a basis for constructing the curve for fluid distribution in the oil-gas transition zone. In the transition zones so derived, the oil begins with a nonvanishing saturation at the water-oil contact and terminates with a similar saturation at the top of the gas-oil contact. The gas-oil transition zone begins with an equivalent nonvanishing gas saturation.

Introduction

It has been a common assumption for some years that the nature of the fluid distribution in virgin reservoirs, and in particular that in the transition zones between the oil and water and between the oil and gas sections, can be computed by a simple application of capillary pressure data. The results of such calculations appear to have been first reported by Leverett.[1] The latter, however, indicated only the numerical values of the parameters used in the computations, without explicitly describing the procedure. Leverett's illustrative calculated transition zones are reproduced in Fig 1. Although no critical study of the apparently obvious method of calculation has been published, one cannot proceed very far in the computation without encountering some rather fundamental questions not yet answered in the literature.

This paper is not written under the pretense that the whole transition-zone problem has been fully and satisfactorily solved. Its purpose, rather, is to discuss suggestions for its treatment, much of it admittedly hypothetical, and emphasize the nature of the uncertainties arising therein; for the literature, as now available, gives little indication that there are any problems still outstanding.

The Transition-zone Equation

The basic equation, which presumably gives directly the fluid distribution without recourse to any further consideration, is:

$$\Delta p = (\gamma_1 - \gamma_2)gh \qquad [1]$$

where γ_1, γ_2 are the densities of the two contiguous fluids, h is the height above the "capillary-free" zone of complete saturation with fluid 1, g the acceleration of gravity, and Δp is the capillary pressure across the average interface at the height

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[1] References are at the end of the paper.

h. Eq 1 is inherently correct. It is its application which gives rise to questions, as will be seen presently.

Unless the capillary pressure curve is initially obtained using the actual fluids 1 and 2 to which Eq 1 is applied, which apparently is seldom done in practice, the capillary pressures are inferred from their relationship to the interfacial curvatures, as:

$$\Delta p = \sigma_{12} C(\rho) \qquad [2]$$

where σ_{12} is the interfacial tension between the two fluids, and $C(\rho)$ is the mean curvature of the interfaces at the liquid saturation ρ. Thus from the capillary-pressure data for the specific fluids used in the measurements the function $C(\rho)$ is computed, also by applying Eq 2. From the capillary pressures as usually reported, this function will have a graphical representation as shown by the solid curve in Fig 2. It is now *assumed* that the function $C(\rho)$ represents a universal relation,[a] for the particular porous medium of interest, and can be used to transform Eq 1 as:

$$C(\rho_w) = \frac{\gamma_w - \gamma_o}{\sigma_{wo}} g h_w \qquad [3]$$

when applied specifically to the water-oil interfaces in a sand in the water-oil transition zone. Choosing the values of $\gamma_w - \gamma_o$ and σ_{wo} pertaining to the particular oil-water system of interest, Eq 3 presumably provides an immediately applicable formula for computing the relation between h_w and ρ_w.

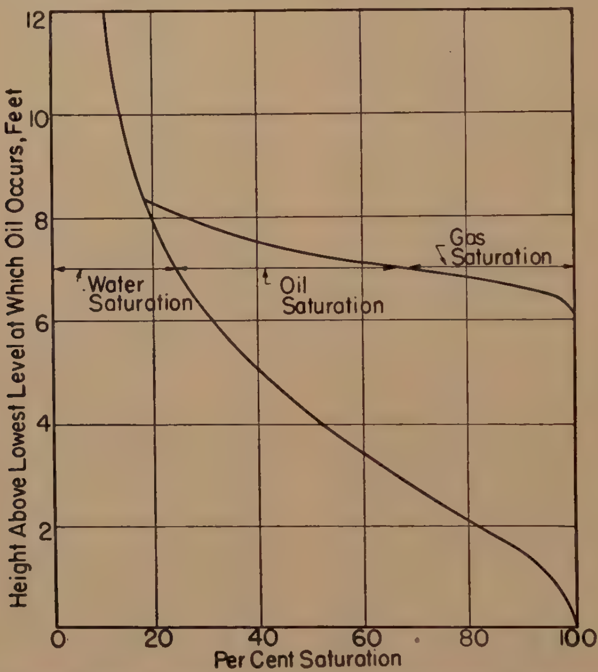

FIG 1—WATER-OIL AND GAS-OIL TRANSITION-ZONE FLUID DISTRIBUTION CALCULATED BY LEVERETT.

CHOICE OF THE CAPILLARY PRESSURE CURVE

The essence of the discussion to be presented here concerns the type of capillary

[a] While such is plausible, in clean sands, evidence that it is not always valid has been reported by G. L. Hassler, E. Brunner, and T. J. Deahl.[3]

pressure or curvature curve to be used in Eq 1 or Eq 3. This is a matter which has been given virtually no detailed consideration. In fact, recent work on the application of capillary pressure data to the determination of connate water saturations seems to have given rise to the impression that the curves for capillary pressure vs. saturation obtained in such experiments also control all aspects of the fluid distribution in interphase transition zones. As originally emphasized in the soil science literature,[3] and also observed in early investigations[1,2] pertaining to oil production, there are two basic types of relationships for capillary pressure vs. saturation. The one refers to a desaturation or drainage of the wetting phase from a rock under pressure or gravity. The other describes the process of wetting-phase absorption or imbibition against an applied pressure or the downward pull of gravity. While these two usually merge in the range of low wetting-phase saturation, they differ markedly at high liquid saturations. Typical of some of the imbibition curves shown by consolidated porous materials is the lower dashed segment in Fig 2.

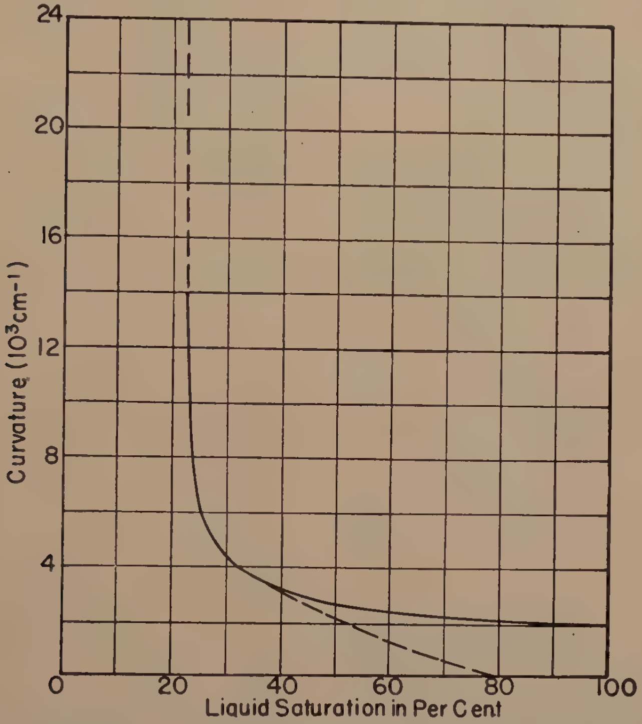

FIG 2—HYPOTHETICAL CURVATURE-SATURATION RELATION IN A POROUS MEDIUM. Solid curve, drainage; dashed lower segment, imbibition.

In his original study of capillary phenomena Leverett[1] suggests that "the conditions under which hydrocarbons accumulate in and are produced from the earth will lead to distribution of the fluids corresponding more closely to the imbibition equilibrium than to the drainage equilibrium." He indicates that where "it is necessary to choose between the two sets of data we shall use the lower (imbibition)." In view of the qualitative similarity between the imbibition and drainage capillary pressure curves found by Leverett, his calculated transition distributions (cf. Fig 1) may well have been

the result of applying the imbibition curve, although otherwise it suggests the use of the drainage curve. On the other hand, the remarks quoted do not indicate why imbibition processes may be expected to control the fluid distribution in transition zones, nor do they suggest any inherent difficulties associated with the application of the drainage curves.

Aside from the question of its applicability to the problem of the fluid distribution in the transition zone, there is inherent interest in an examination of the implications of the capillary pressure drainage curve. The solid curve of Fig 2, if reconverted to capillary pressure ordinates, is typical of those observed with consolidated rocks.[2] This curve, it will be noted, begins at a nonvanishing value at 100 pct liquid saturation. The corresponding value of the capillary pressure is the "displacement" pressure, which represents the maximum that can be applied to a liquid-saturated rock before entry of nonwetting phase will develop.

The existence of a displacement pressure or "displacement curvature" immediately appears to invalidate Eq 1 and Eq 3 with respect to values of h lower than given by these equations for the displacement values of Δp or $C(\rho_w)$. This, in itself, is not serious, and can be interpreted as indicating simply that the rock will be fully saturated until this minimum value of h is reached. More disturbing, however, are the implications of the drainage curves immediately above the displacement pressure or curvature. In accordance with most published data, the solid curve of Fig 2 has been drawn to show a nonvanishing slope at 100 pct liquid saturation. This implies the existence and development of stable distributions of arbitrarily low nonwetting-phase saturations as the pressure is increased slightly above the displacement value. If uniformly distributed, the nonwetting phase would certainly be in a dispersed and discontinuous distribution at such low saturations. But a bubble or globular distribution of gas or oil will have zero permeability, and it is difficult to understand how it could be created throughout a rock sample when only its surface is exposed to the nonwetting phase. Moreover, small bubbles, especially, and any dispersed nonwetting phase are inherently unstable thermodynamically, and ultimately would tend to disappear by solution and diffusion through the wetting phase. Finally, if the nonwetting phase is discontinuous, it should not be subject to the requirement of hydrostatic equilibrium of Eq 1. An individual globule of oil trapped in a pore will remain so without appreciable change in curvature at any hydrostatic pressure, and the latter alone will not directly influence its stability, except for the effects of solution and diffusion.

It is possible to explain these difficulties associated with arbitrarily low nonwetting-phase saturations by assuming that instead of representing a discontinuous distribution of separated bubbles or globules the nonwetting phase is localized in continuous filamentary channels comprising only a small part of the total pore volume. While such a situation is conceivable, it would suggest a surprising degree of nonuniformity in the typical small rock sample. Moreover, it would be expected that if such continuous channels could be set up in a capillary-pressure desaturation process they would also be observed in multiphase flow experiments so as to give vanishing equilibrium gas saturations. Yet even the permeability-saturation curves obtained by liquid desaturation processes show in virtually all cases that continuous flow channels of the nonwetting phase do not develop until its saturation builds up to at least 5 to 10 pct. Although experimentation with multiphase flow in this region is very difficult and subject to relatively large experimental errors, the frequency of occurrence of vanishing equilibrium saturations for the nonwetting phase is certainly

not comparable with that in which the capillary pressure apparently rises gradually from its displacement value in desaturation experiments. While it may seem unjustified to question so much of the evidence reported on capillary pressure measurements, it is felt, nevertheless that this apparent discrepancy largely reflects experimental errors in the experiments on capillary pressure drainage. It is anticipated that if such experiments were performed with special care and so as to ensure equilibrium conditions when the capillary pressure just exceeds the displacement value, the curve would have a strictly flat initial segment, with the capillary pressure beginning to rise only after the wetting-phase saturation had been reduced to a value approximating the equilibrium saturation.

These difficulties can be circumvented with respect to the transition zone, even if it should be established definitely that the curves of capillary pressure drainage do not begin with a horizontal segment. For if the capillary pressure curves obtained by imbibition are applied near the zone of complete water saturation, the questions of nonwetting-phase mobility, its stability, and control by hydrostatic forces simply do not arise. In the lower dashed segment of Fig 2, no displacement pressure is shown. Moreover, a zero capillary pressure is exhibited at less than 100 pct wetting-phase saturation. The resulting nonwetting-phase saturation is presumably at least the limiting value for a continuous and mobile distribution, although hysteretic and metastable inclusions of dispersed elements may be part of the whole. While these features automatically avoid the difficulties arising from the application of the drainage curve to the lower regions of the transition zone, it is instructive to consider in detail the circumstances that give inherent plausibility, at least, to the introduction of the imbibition curve.

Application of Imbibition Curves to Problem of Transition Zone

The intuitive feeling that the transition zones are established entirely by drainage processes raises doubt as to the applicability of curves for capillary pressure imbibition. Because of the uncertainty of the detailed mechanism of oil accumulation in reservoir traps, the nature of the fluid redistribution following the initial entry of the petroleum fluids is likewise not definitely established. Nevertheless, the physical processes determining the fluid distribution in the transition zone can be analyzed without defining in detail the basis mechanism of oil migration and accumulation. There is general agreement that prior to the accumulation of the oil the reservoir rock was saturated with water. There can also be little doubt[a] that the initial replacement of the water by the invading oil left a water saturation higher than the "irreducible" water content subsequently found on discovery at appreciable elevations above the water contact. In the upper parts of the pay the establishment of the connate water saturation therefore must have involved a desaturation process of gravity drainage opposed by capillary forces, as commonly assumed. Associated with this drainage, however, there must have occurred an upward movement of oil from the lower parts of the oil zone to replace the downward draining water. And the latter, in turn, must have involved an increase in water saturation—an imbibition—in the region near the oil-free and water-saturated section. It is therefore to be expected that the final fluid distribution developed by the countercurrent flow of water and oil will be

[a] Strictly speaking, this is an assumption, though it would seem to be surprisingly accidental if the rate of accumulation were everywhere and always exactly such that gravity forces could suffice to establish complete drainage equilibrium throughout the formation during the initial accumulation process, and even before the position of the ultimate capillary-free water level were definitely established.

determined by the characteristics of the capillary pressure drainage curve in the main body of the oil pay and the upper layers of the water-oil transition zone, and detailed mechanism of initial accumulation and distribution of the free gas phase is even more conjectural than when the oil phase alone enters a reservoir trap. Again,

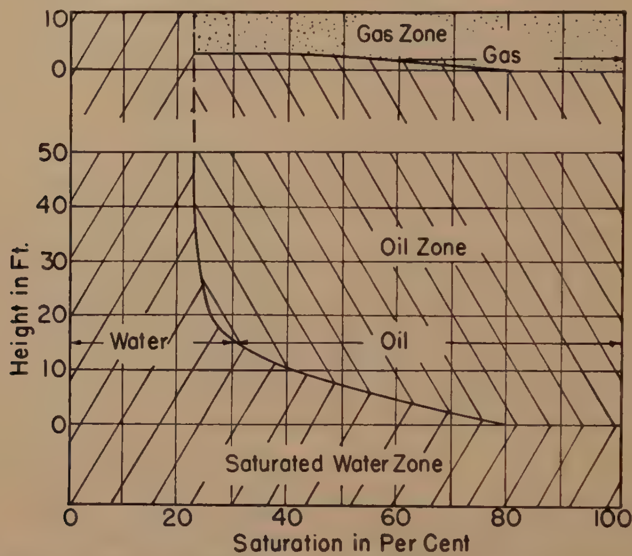

FIG 3—CALCULATED SATURATION DISTRIBUTIONS IN WATER-OIL AND OIL-GAS TRANSITION ZONES, USING THE CURVATURE-SATURATION FUNCTIONS OF FIG 2.

Water-oil and oil-gas density differences assumed = 0.3 and 0.5 g/cc; water-oil and oil-gas interfacial tensions assumed = 30 and 20 dynes/cm.

by those of the imbibition capillary pressure curve in the region immediately adjacent to the water contact. Since the imbibition and drainage curves merge at moderate saturations, the exact point of change-over between the two will be of little importance. In any case, the oil saturation in the transition zone will begin at a nonvanishing value in a manner quite similar to that which would follow from a drainage curve with initial horizontal segment. The transition water-oil zone distribution, as calculated from the imbibition curve of Fig 2, assuming $\gamma_w - \gamma_o = 0.3$ g/cc, $\sigma_{wo} = 30$ dynes/cm, is plotted in Fig 3.

While the general problem of the gas-oil transition zone when a free gas phase is present is basically similar to that of the water-oil zone, the former gives rise to additional complications. In fact, here the however, regardless of the manner in which the gas and oil entered the trap, the application of the curve for capillary pressure drainage at high liquid saturations encounters the difficulties of gas-phase mobility, stability, and the validity of the hydrostatic pressure balance requirement, unless an initial horizontal segment be assumed. And here, too, although the latter condition may be considered as a probable characteristic of the drainage curve, independently of the transition-zone problem, the use of the curve for imbibition capillary pressure near the gas-oil contact appears to be inherently the more reasonable procedure. For if the initial gas-oil distribution be assumed as substantially uniform, as the result of the dynamic phase displacement process, the redistribution to the state of increasing oil saturations on approaching the gas-oil contact will again require

countercurrent gas and oil movements in which the lower parts of the transition zone "imbibe" the oil draining down from above. Thus the gas-phase saturation will also start at the nonvanishing value as a limiting continuous phase left by the imbibition process.

Although in the theory outlined above only the lower parts of the oil-water transition zone are considered as controlled by imbibition processes, the application of the desaturation curve raises questions of physical interpretation when applied to the top of the gas-oil transition zone. For, as indicated by Fig 1, which apparently is the result of such application, the oil saturation will decline continuously to zero, as the total liquid saturation approaches the irreducible minimum already occupied by the connate water. Evidently the previously mentioned difficulties of mobility, stability, and hydrostatic pressure control, associated with the necessarily discontinuous distribution at the very low oil saturations—unless accidental filamentary distributions are assumed—must be faced here, too. However, in this region the drainage curve does not permit a simple modification for resolving the dilemma.

In the light of the almost complete absence of basic information on capillary equilibrium in three-phase systems,[a] the difficulty just mentioned might well be considered simply as an unsolved problem. However, it is possible to construct a plausible tentative solution by generalizing the concepts pertaining to two-phase distributions. First, it is to be noted that both the oil and gas are basically nonwetting phases in a water-wet rock. The conventional two-phase capillary pressure experiments are commonly interpreted as applying to three phases with the oil adding to the water as a composite liquid. But this is only an assumption. It is reasonable when the gas-phase saturation is low and does not appreciably exceed the minimum needed for phase continuity. Certainly, however, when the oil phase approaches the discontinuous distribution, the assumption that it forms a continuous extension of the water phase with curvatures the same as for an equivalent total water saturation becomes highly questionable. Indeed, it is just this which leads to the difficulties mentioned.

More plausible is the supposition that the gas and oil change places, as it were, when the gas-phase saturation appreciably exceeds that of the oil phase. While intuitively it would appear that the oil phase will always lie adjacent to the water and the gas phase will occupy only the central pore channels, probably this reflects mainly a dynamic behavior largely controlled by their relative viscosities. In fact, the only reported three-phase permeability studies[4] show that at moderate water contents the relative permeabilities, in which the direct viscosity effects are removed, for the gas and oil vary with their own saturations in a very similar manner.

It does not seem unreasonable, therefore, to consider the high saturation gas phase in the upper parts of the gas-oil transition zone as the supplementary wetting phase superposed on the water phase, analogous to the oil near the oil-saturated zone. In a strict sense, of course, neither the gas nor the oil will actually be true wetting phases, and if the irreducible water saturation should leave completely dry and exposed parts of the grain surface between the pendular rings, the oil probably would cover them in preference to the gas. It is only suggested that the gross interfacial geometry between the gas and oil be determined by considering the gas and water as the wetting-phase equivalent rather than the oil and water. In any case, the previous difficulties are automatically resolved by this supposition, for now the countercurrent upward migration of gas and

[a] Since this paper was written some interesting three-phase capillary pressure studies have been reported by J. H. Welge.

downward drainage of oil during the establishment of equilibrium in the transition zone again becomes an imbibition process in the upper layers with respect to the composite water and gas equivalent wetting phase. Eq 1 is then applied using the curve for capillary pressure imbibition with h representing the depth below the top of the transition zone.

The exact point of change-over between the gas and oil as the apparent single nonwetting phase is not clear at present. Probably it will occur when the oil and gas phases have approximately equal saturations. Moreover, since the capillary pressure curves are inherently subject to hysteretic effects and depend on the past history and initial conditions of the system, no single curve will necessarily apply to the oil-water transition zone and both the lower and upper parts of the gas-oil transition zone. However, in principle these are subject to experimental determination, and indeed the investigation of three-phase capillary pressure curves merits much further study. From a practical standpoint, these uncertainties will affect only the quantitative details of the transition-zone distributions. Their gross characteristics and thickness will be largely fixed by the sharpness of the "bend" in the capillary pressure curve and the density and interfacial tension constants.

A gas-oil transition-zone distribution calculated by the procedure outlined, using the imbibition curvature relation of Fig 2 and $\sigma_o = 20$ dynes/cm, $\gamma_o - \gamma_g = 0.5$ g/cc, is plotted in the upper part of Fig 3, assuming a change-over nonwetting phase saturation of 39 pct. Both the gas and oil saturations of the transition-zone boundaries begin with the nonvanishing values presumably left by the imbibition processes postulated above. Moreover, as is evident immediately from Eq 3, when transformed to the gas-oil interface equilibrium, the gas-oil transition zone is thinner, by several fold, than the water-oil transition zone, for the same curvature function.

The calculation of the distribution of the transition zone fluid does not of itself determine the thickness of the oil zone. The latter is fixed by the total oil content of the reservoir. The transition zones merely represent boundary layers adjoining and superposed on the oil-saturated section. Of course, if the latter is very thin the transition zones may span the whole of the oil pay. While such extreme cases apparently have been observed, they represent exceptional situations. On the other hand, if the capillary pressure drainage curve is considered as approaching the "irreducible" saturation asymptotically, the transition zone with respect to the water phase would, in principle, extend to the very top of the reservoir structure. From a practical point of view this is of little importance, since the saturation varies but slowly in the region of high capillary pressures. However, if the irreducible saturation is visualized as developing suddenly by a breaking of the continuous funicular films when a critical capillary pressure is exceeded, the transition zone will be correspondingly limited. As the latter situation appears to be more plausible, it has been so assumed in Fig 2. Under this assumption, generally there will be no need to take into account the capillary pressure balance in the gas zone with the water phase.

It should be emphasized that the suggestion for calculating the nature of the gas-oil transition zone by an application of a modified interpretation of the conventional type of two-phase capillary pressure curves is not proposed as a final solution to the problem. It represents only a working hypothesis and convenient artifice when only the normal two-phase curves are available. Except for the fact that the finer pore interstices are actually occupied by the connate water, the behavior of the gas and oil phases in the gas-oil transition zone

would simulate that of a two-phase system in which neither the gas nor the oil completely wets the solid internal surface. For quantitatively accurate calculations, it will be necessary to apply empirically determined curves for three-phase capillary pressure obtained by desaturation or inhibition processes corresponding to those actually occurring in the reservoir. The illustrative calculation underlying the gas-oil transition zone plotted in Fig 3 has been presented only to show the qualitative characteristics of this transition zone and the gross features of the physical processes involved.

It should be noted, finally, that the considerations and calculations set forth here refer only to strictly uniform media of identically the same capillary functions throughout. Unfortunately, in practice the reservoir formation usually has such vertical variations, directly reflected in its permeability, as may well mask completely any regular trend in the saturation distribution in the transition zone. The ideal situations offering opportunities for quantitatively checking calculated saturation distributions will therefore be limited. It is felt, nevertheless, that it would be highly desirable to attempt such comparisons, where possible, in order to help to clarify the physical principles of capillary phenomena.

ACKNOWLEDGMENT

The writer is indebted to Dr. Paul D. Foote, Executive Vice-President of the Gulf Research and Development Co., for permission to publish this paper.

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Core Analysis of Fractured Dolomite in the Permian Basin

By Burton Atkinson,* Member and David Johnston,* Junior Member AIME

Abstract

Evaluation of Ellenburger reservoirs in West Texas has been an uncertain matter at best because of the lack of cores and suitable core-analysis method. Large amounts of oil are produced from sections from which sample cuttings are obtained that contain little porosity and no oil saturation. It has long been realized that the formation in some areas contained numerous fractures and solution cavities that probably contained the major part of the oil present but the magnitude of the porous system containing oil has been unknown.

Diamond coring equipment, used in the mining industry for many years, has been developed for oil-field use to obtain high core recovery in fractured dolomite that is not possible with conventional coring equipment.

A 36-ft section of the core recovered from a fractured Ellenburger reservoir was analyzed by a unique but simple method to obtain the first definite evaluation of one section of the producing formation. The cores and the method of analysis used are described and the results are discussed in some detail.

1


2


Fig 1 and 2—Extracted core segments illustrating character of fracturing.

Discussion

The first successful known analyses of cores recovered from the Ellenburger formation in the Permian Basin area were made on cores recovered with the use of diamond core heads. Conventional coring methods previously used have had low core recovery and standard methods of analysis have proved to be inadequate for evaluation of those cores that were recovered.

Core Description

The Ellenburger formation to be discussed was cored using diamond core heads and oil-base drilling fluid. Of the total 103 ft cored to a depth of 8893 ft in the Ellenburger, 99 ft or 96 pct was recovered.

The dolomite cores were described as gray to white, crystalline to coarsely crystalline, with chert and calcite inclusions. Occasional shale partings ⅛ to ¼ in. in width were noted. A small amount of green clay was found in some of the coarsely crystalline material. No intergranular porosity was found by inspection in any of the cores.

The core was highly fractured over most of its length with not more than two continuous feet that failed to contain fractures. The fractures were nearly vertical and varied in width from those barely visible to as much as one millimeter. Scattered solution voids, or vugs, as large as 3 cm in diameter occurred in association with some

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* Humble Oil and Refining Co., Midland, Texas and Refugio, Texas, respectively.

of the fractures. Most of the surfaces of the vugs and the enlarged fractures were covered with dolomite crystals, apparently the result of secondary deposition. Some of the smaller fractures were partially filled with redeposited dolomite and clay.

When the cores were broken some apparently unconnected vugs were found. At least one of the vugs contained clear salt water, whereas the water now underlying the oil is sulphur water.

The oil-base drilling fluid wet the surface of the fractures and vugs but did not penetrate the matrix to any noticeable extent. Freshly broken surfaces failed to show evidence of any oil content under the fluoroscope. Fig 1 and 2 illustrate to some extent the character of the fracturing present. The cores are 3 in. in diameter.

Sampling and Analysis

The upper 63 ft of the core recovered was analyzed in the conventional manner by a contract crew in a mobile laboratory. Small plugs cut from the core had an average porosity of only 2.5 pct and only one had a permeability of over 0.1 millidarcy. From this it was evident that, because of the irregularity of the fracture and vug system, it was impossible to obtain a small sample that was representative of the full cross section of the core. It was also the opinion of those present that most of the oil was originally contained in the fracture and yug system and that little if any oil was contained in the matrix.

The last 36 ft cored and recovered, from 8857 to 8893 ft, was broken as nearly as possible into 6-in. segments. These segments were quick frozen and one-half were sent for analysis to a commercial laboratory which was asked to devise a method for obtaining the overall connected porosity of the full 3-in.-diam segments including all the fractures and vugs. The porosity of the matrix could then be established by conventional analysis on small portions of the core not visibly affected by fractures. In this way the two general types of porosity evident could be evaluated. The laboratory was instructed not to attempt any permeability measurements at that time as it was thought that productivity data obtained in flow tests on the completed wells would contribute more to the knowledge of the permeability of the fracture system.

The following procedure was used in the laboratory. Two to four adjacent samples were submerged, while still frozen, in toluol in a modified Dean-Stark water extraction apparatus. The water extracted in 24 hr was determined.

The cores were then dried and weighed. Large openings were covered with thin sheets of rubber after which the cores were subjected to a high vacuum before being saturated with water. The difference between the weight of the water-saturated cores and the dry weight, including the weight of the rubber, was recorded as pore volume. The bulk volume of the core sample was measured by displacement of water while the core was still wet. In this manner, water saturation was determined for groups of adjacent core sections while the total connected porosity was determined for individual samples. Specimens for the matrix were then taken so as not to include any vugs or fractures, evacuated, weighed and saturated with water. From the increase in weight and the bulk volume of the sample the matrix porosity was calculated.

The large size of some of the vugs in comparison to the size of the 3-in.-diam core probably resulted in total measured porosity values that were lower than the actual porosity of the section before it was cut because the rubber coating fails to follow the circumference of the core across large openings. Since much larger specimens can be handled in the laboratory, it is believed that improved accuracy may be obtained by cutting larger cores where possible and subjecting the entire section cut to analysis. Breaking of cores into short lengths will also result in lower porosity values as the cores usually break where vugs are promi-

nent with chipping that tends to decrease the measured size of the vugs. It was also realized that future cores should be extracted for individual water determinations instead of for group averages.

ble error, probably of small magnitude, in the values of residual water saturation.

Fig 3 shows the total porosity of the matrix and fracture system plotted against depth. It will be noted that, as expected,

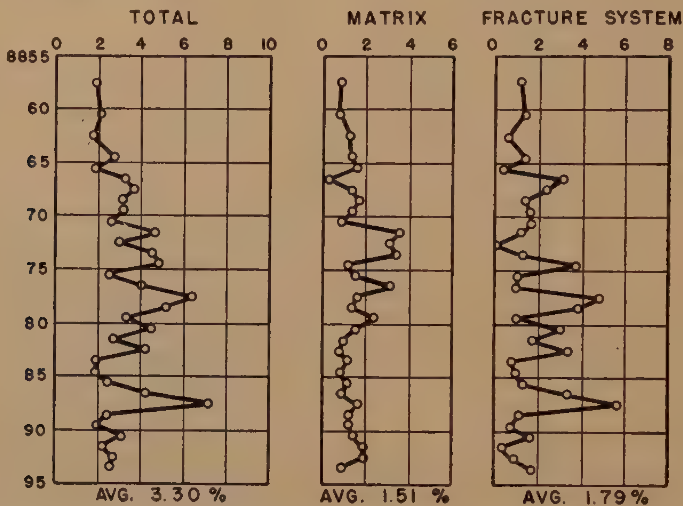

FIG 3—POROSITY OF MATRIX AND FRACTURE SYSTEM VERSUS DEPTH, FRACTURED ELLENBURGER.

RESULTS

Total connected porosity averaged 3.30 pct of the bulk volume of the samples. The matrix porosity averaged 1.51 pct; specimens used to determine the matrix porosity averaged 50 g in weight, the core segments, 1300 g.

Indicated values of the porosity of the connected fractures and vugs, referred to as the fracture system, varied from one value less than zero to a maximum of 5.59 pct with an average of 1.79.

The average of the water percentages of the 11 groups of cores extracted was 47.3 pct of the total pore space. The arithmetical average of the average matrix porosity of the groups was 47.4 pct of the total pore space, which is seemingly in good agreement with the average water saturation. However the average of the individual determinations of matrix porosity is 45.7 pct of the total porosity. The extraction of cores in groups introduced an indetermina-

the magnitude of the fracture porosity is more variable with depth than is that of the matrix porosity.

In Fig 4 the percentage of total pore space that is matrix or intercrystalline porosity is plotted against the percentage of total pore space occupied by water. Although, as has been pointed out previously, the data are somewhat in error because of the grouping of samples for water extraction it is possible that the average trend shown is significant. The upper portion of the curve is for samples in which the porosity of the fracture system is in general lower and less developed than the porosity of the matrix. In this portion of the curve the percentage of the total porosity occupied by water is slightly greater than the percentage of total porosity made up by matrix porosity. This indicates that the matrix is completely filled with water in this region and that some water may exist in the smaller fractures.

In the lower portion of Fig 4, for which

a more highly developed fracture and vug system may be expected, the water percentage is less than the amount of matrix porosity. This suggests the presence of a type porosity, intermediate between the system and that only a negligible amount occurs in the matrix.

In Fig 5 the various types of porosity determinations were arranged in increasing order of porosity for each type. Natural

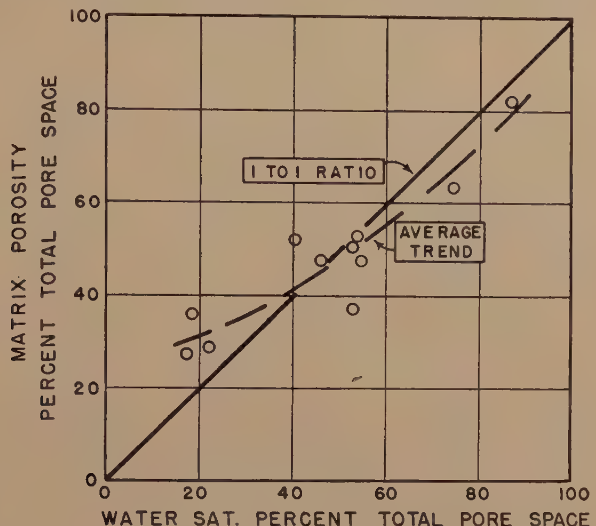

Fig 4—Matrix porosity versus water content.

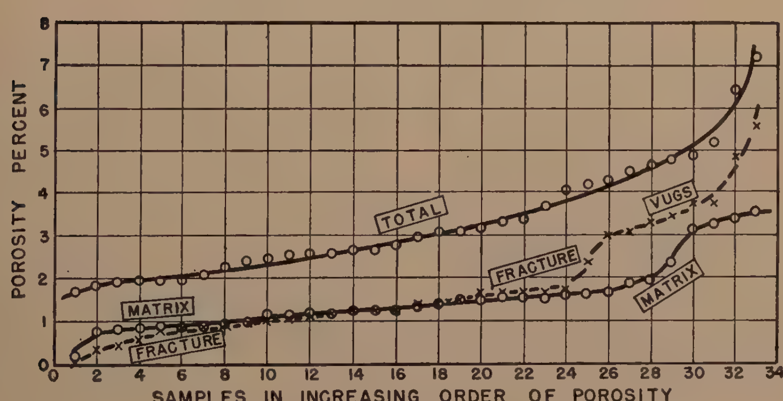

Fig 5—Occurrence and magnitude of porosity types.

two general types, that is possibly caused by pores enlarged by solution around the edges of the vugs and fractures. This hypothesis is based on little evidence and more supporting data should become available before it is accepted. On the whole the present data indicate that the oil present in the portion of the reservoir cored lies almost entirely in the fracture and vug

data plotted in this manner usually fall on a nearly straight line with sharp curves on each end. The curve of total porosity satisfied this condition rather well for the small amount of data involved. The curve of fracture and vug porosity, however, undergoes about a 1 pct displacement between samples 24 and 26. Inspection of the cores indicates that the 8 core segments

with the greatest fracture-system porosity also have a vug development that is easily visible.

The upper branch of the curve of matrix porosity on Fig 5 also fails to conform to the shape expected for a group of natural data. The four or five points that are displaced from the lower branch may be a further indication of the presence of a porosity that is intermediate between the fracture system and matrix porosity.

On Fig 6 the fracture-system porosity and the matrix porosity are each plotted against total porosity. No clear-cut relationship between matrix and total porosity is discernible. The porosity of the fracture system has a fairly good linear relationship with total porosity and reaches the point of zero fracture-system porosity at the 1.5 pct average value of the matrix porosity. When the values of matrix porosity are plotted against fracture-system porosity, no relationship is noted.

The analysis of this short section indicates that there is approximately 139 bbl of space per acre-foot that is available to contain oil. This will appear to be a very low figure to those who have been accustomed to work with sandstone reservoirs, but when it is understood that some Ellenburger reservoirs contain over 500 ft of oil section the magnitude of the reserve possibly present becomes considerable.

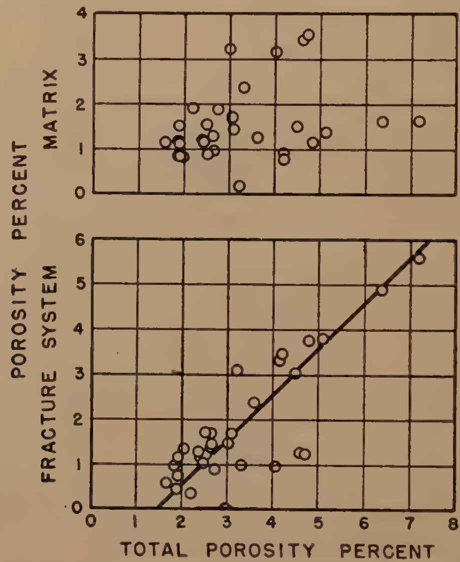

Fig 6—Relationship of porosity types.

It should be realized, however, that there are important changes in lithology within the Ellenburger reservoir from which these cores were taken and that it is extremely unlikely that the section analyzed is typical of the entire reservoir. Producing characteristics vary widely from field to field, and no accurate data is available on flushing efficiencies or recovery factors.

This discussion has been presented to illustrate the practicability of obtaining and analyzing cores from fractured formations in which an increasing number of new reserves are being discovered.

Acknowledgment

Thanks are due the Humble Oil and Refining Company for permission to publish this paper, to Core Laboratories, Inc., for the laboratory work performed, and to the several operators in the West Texas area who have made available the results of their experience in diamond coring.

Displacement of Oil from Porous Media by Water or Gas

By Henry J. Welge*

(Tulsa Meeting, October 1947)

Abstract

Laboratory apparatus has been devised which permits study of the displacement of oil from cores by water and by gas. The cores used contained interstitial brine as well as oil.

Experiments were run to determine the comparative effect of varying the properties of the fluids used. No great effect was noted on the maximum displacement achieved. This observation made it unnecessary in initial work to use fluids in their exact reservoir conditions. Consequently, the displacements were run at near-atmospheric pressure in Pyrex glass equipment, using stripped crude oils.

Introduction and Theory

The chief object of this work has been to determine the efficiency of gas and water as primary agents for displacing oil from reservoir rock under laboratory conditions in which capillary phenomena were predominant. To this end the maximum displacement of oil from cores has been ascertained. This maximum displacement may not be equal to the maximum displacement from a reservoir; but it will be a close approximation to it sometimes, and other times the laboratory information will be useful in reservoir engineering predictions. It is believed that the laboratory experimental maximum represents the upper limit for the reservoir recovery.

The experiments were carried out by obtaining cores of interest from the reservoir, and filling the pores with interstitial brine and oil with the restored state technique.[1] Then the oil was displaced from the core as described later, either by brine from below, or by gas from above. The former type of displacement suggests analogy to production by water drive, but not to water flooding, for reasons discussed below. The latter type of displacement is believed to simulate production by gas cap displacement.

The displacements were performed by what may be termed the capillary-pressure method. The cores are placed in capillary contact with an oil-wetted membrane which has very small pores (about 1 micron in diameter). Pores of this size will transmit oil but prevent the passage of gas or water, unless the pressures used are higher than the capillary pressures employed in this work. Accordingly, use of the membrane makes it possible to apply a capillary pressure differential between the displacing phase and the oil in the core.

As in the displacement of brine toward that condition of oil and water distribution existing originally in the reservoir,[1] it may not always be desirable to reduce the oil saturation in this experiment to an absolute minimum. With reservoirs having small productive closure, it is preferable to evaluate and use a displacing pressure no higher than the capillary pressure, Δp, which will ultimately become available for displacement in the reservoir. This pressure may be calculated from a knowledge of the density of the oil-in-place, d_o, the density of the displacing phase, d_f, and Δh, the vertical distance between the section of the

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* The Carter Oil Co., Tulsa, Okla.

[1] References are at the end of the paper.

reservoir from which the core originated and the estimated ultimate position reached by the contact plane separating oil and displacing phase at economic abandonment. The formula is:

$$\Delta p = g\Delta h\ (d_o - d_f)$$

where g is the acceleration of gravity.

The information given by the type of test indicated may require special interpretation to yield a quantitative measure of the oil obtainable by horizontal water injection. Two factors are probably different when secondary recovery is simulated in the laboratory:[2] (1) when no interfacial barrier is employed, the capillary pressures imposed can be very small, and may in addition vary significantly from point to point in the core; and (2) the velocity of fluid flow through the pores may be high enough to influence the amount of displacement. Field and laboratory experience is believed to indicate that secondary recovery methods would obtain somewhat less oil than primary methods, if the latter can be efficiently employed.

Displacement of Oil by Water

If the efficiency of the displacement of oil by water is to be studied, the core is removed from the connate water apparatus and transferred to the cell shown in Fig 1. An excess of oil normally clings to the core when it is first lifted from the connate water apparatus. This oil must be wiped off, but in doing so care must be taken not to remove any oil that is inside the pores. Tests have shown that different experimenters can approach the same correct oil saturation within about 30 mg of oil, or about 1 pct of the pore volume in most experiments.

Stripped crude oil from the field being studied is used for the oil phase. A brine is employed which contains approximately the same concentration of sodium, chloride, calcium, and hydrogen ions as the brine in the reservoir from which the core originated.

The Buchner funnel of Fig 1 is treated with silicones or methyl chloro-silanes to render its surface oil-wetted and water repellent.[3,4] Kleenex paper, which is likewise treated with silicones, is used to ensure capillary continuity between the oil phase in the core and the external column of oil. The pores in the fritted disc and the stem of the funnel are filled with the stripped crude oil. The cell is held in the inverted position from that shown in Fig 1 while mounting the core in place. The flat face of the core[1] should be placed in contact with the paper. At this point the cell is returned to the position shown in Fig 1, and a hypodermic needle is passed through the neoprene stopper. As brine is now poured in rapidly through the Saran tube, the air in the funnel can escape through the needle; when all the air is replaced by brine, the needle is withdrawn. Nitrogen pressure is applied to the water phase in increments of about ¼ to ½ psi until the oil level no longer rises, thus indicating that the oil saturation in the core has been reduced to the minimum obtainable by this displacing technique. The displacement may require 1 to 2 weeks to run its complete course.

It is thought desirable to have the denser fluid (the brine in this case) occupy the lower part of the apparatus, as in the natural reservoir, although recent experiments have indicated that this precaution may not be necessary.

At the end of the displacement, the water and oil left in the core are measured by analysis. This is done by boiling the core with CCl_4 in the extractor shown in Fig 2 (or by a method similar to that recently described by the U. S. Bureau of Mines[5]). After all the water has collected as shown (8 to 24 hr of boiling), the apparatus may be tilted to bring the water layer down into the narrow calibrated tube. Finally the core is completely extracted with CCl_4 in a Soxhlet extractor. The density of the extract is accurately measured with a pycnometer at a reference temperature. This

density is a sensitive function of the concentration of oil in CCl_4 and permits the concentration to be determined with the aid of a suitable calibration graph. From rises. This test is similar to the restored state test for connate water determination, the significant points of difference being that oil instead of water is displaced by gas

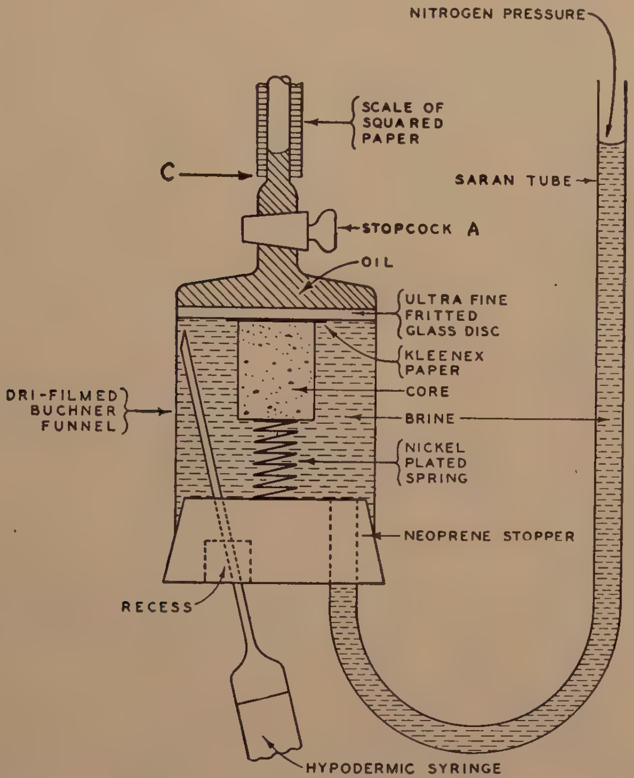

FIG 1—APPARATUS FOR CAPILLARY DISPLACEMENT OF OIL BY WATER.

this the quantity of oil extracted may be ascertained.

OIL DISPLACEMENT BY GAS

In the event the oil is to be displaced by gas with gravity drainage of the oil, the core is transferred from the connate water apparatus to that shown in Fig 3. This cell is also treated with silicones to render it oil-wetted. The fritted glass plate is saturated with crude oil, which also fills the curved glass tube and riser arm. The body of the Buchner funnel is filled with nitrogen, the pressure of which is gradually increased until the oil level in the open arm no longer and that at the end of this test the core contains oil, water and gas.

At the end of the displacement by gas, the core is weighed, then placed in the water extractor shown in Fig 2. Subtraction of the (connate) water found from the residual weight of liquids yields one measurement of the residual oil, while the density data from a final Soxhlet extraction with CCl_4 yields another.

It should be borne in mind that only very small fragments of the reservoir rock in question can be used in a displacement study. It is possible that large scale trapping of oil may occur because of inhomo-

geneities within the reservoir. In such an event, lower overall recoveries of oil might be expected than are indicated by the results reported in this study. There are

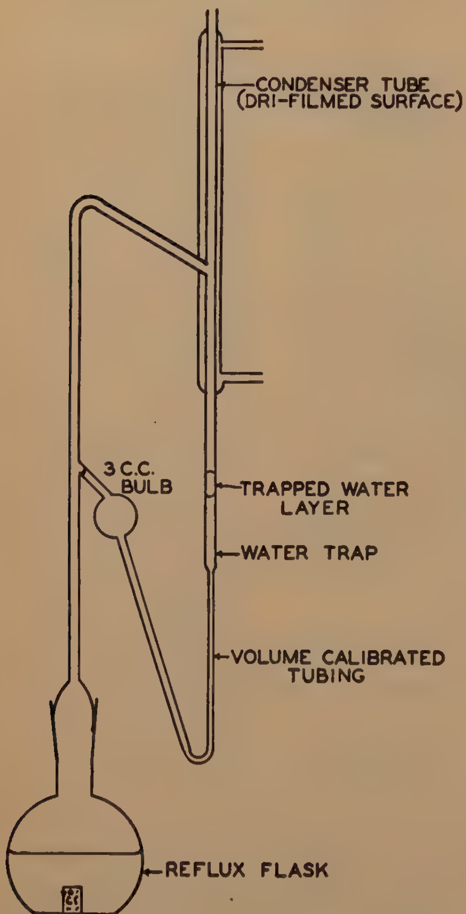

Fig 2—Water extractor, carbon tetrachloride type.

also complications introduced by flowing pressure differentials, nonhomogeneous parallel strata, and well locations, all of which tend to make pool recoveries lower than the maximum laboratory displacement.

Results and Comment

A typical displacement from a core of Smackover oolitic limestone is illustrated in Fig 4. The solid curve represents the restored state process of displacing water by oil until only connate water remains. The negative values on the ordinate scale show where the pressure on the displacing phase

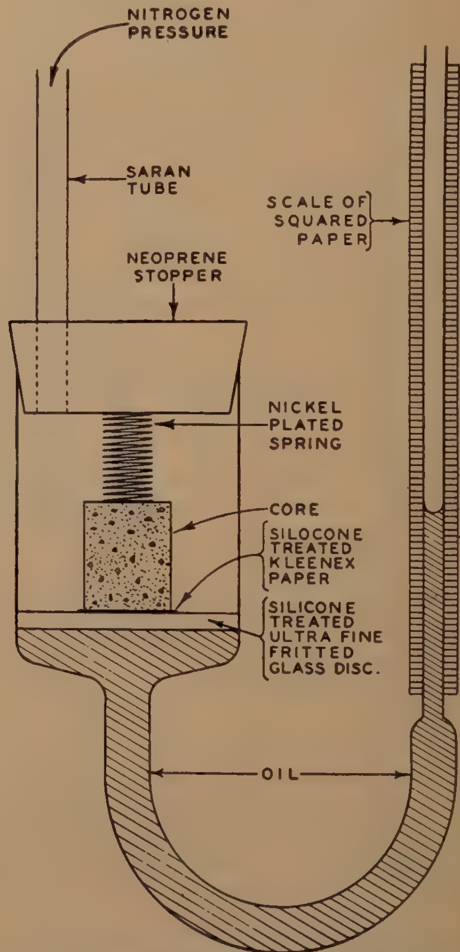

Fig 3—Apparatus for capillary displacement of oil by gas.

must be greater than that of the oil phase. The upper dashed curve then indicates the way in which the oil is expelled again from the core by water. The lower dashed curve similarly illustrates gas displacement. In each, a typical S or knee-shaped structure is evident. With this core approximately the same amount of oil is recovered by either method.

An illustration of oil displacement from a preferentially oil-wetted core is shown in Fig 5. It should be noted that the oil tends rock spontaneously imbibes water with concomitant expulsion of oil.

Table 1 summarizes the data so far ob-

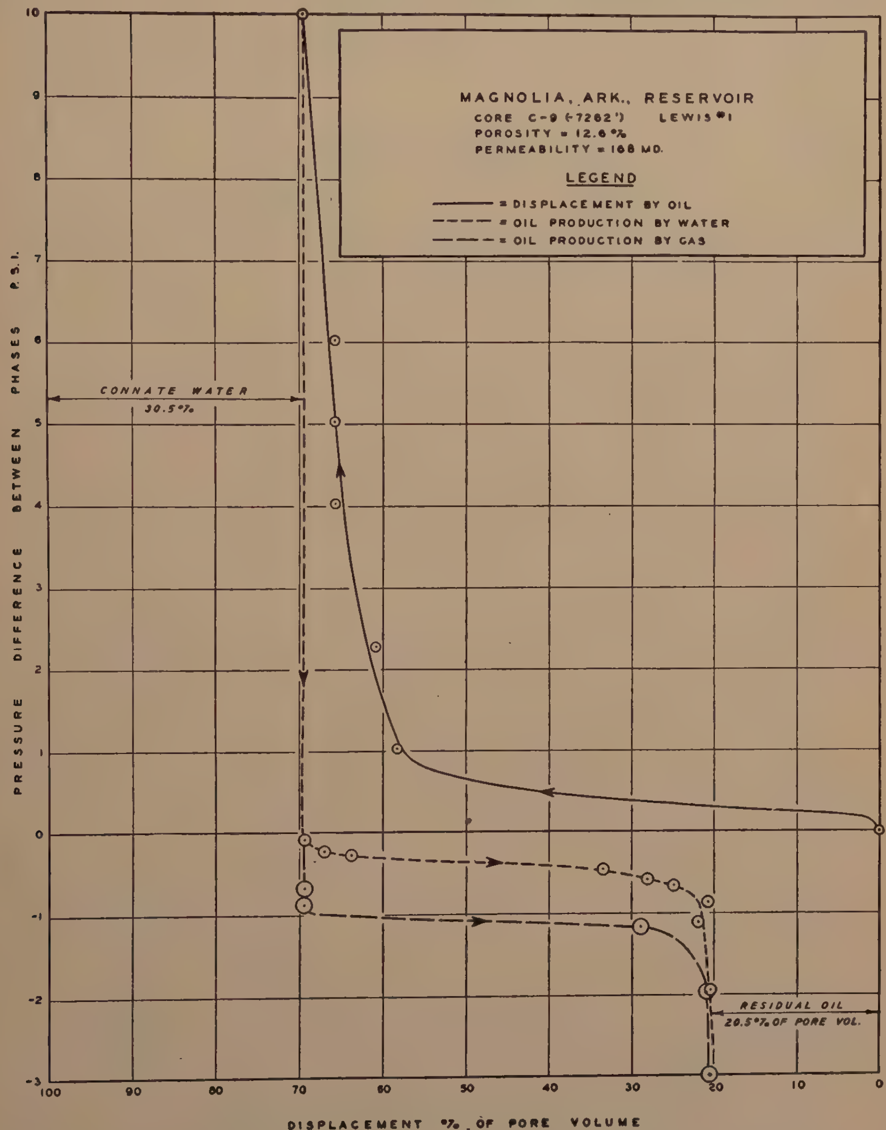

FIG 4—EXPERIMENTAL OIL PRODUCTION WITH THE REVERSIBLE DISPLACEMENT CELL.

to enter the pores spontaneously, and does not require forcing in under pressure.

With a core of strongly water-wetted material, the displacement proceeds as shown in Fig 6. It is to be noted that this

tained on oil-field cores. The results show that either gas or water displacement is an efficient means of removing the oil from the limestone cores studied. After displacement only 10 to 20 pct of the pore

volume retains oil. However, with some types of cores the water appears to displace less oil than the gas. In the case of the quartzitic sandstone reservoir (Elk Basin), the water tends to give lower recoveries, especially in the tighter sands having permeabilities less than about 100 md. Here the tendency of the oil to cling to the oil-wetted type of reservoir rock may be responsible for the by-passing of considerable portions of oil by the water. The relative inefficiency of the water drive in some of the argillaceous sandstone cores has been somewhat surprising. In all examples given, the results are supported by an analysis of the core, after the displacement is completed, for the residual oil and brine.

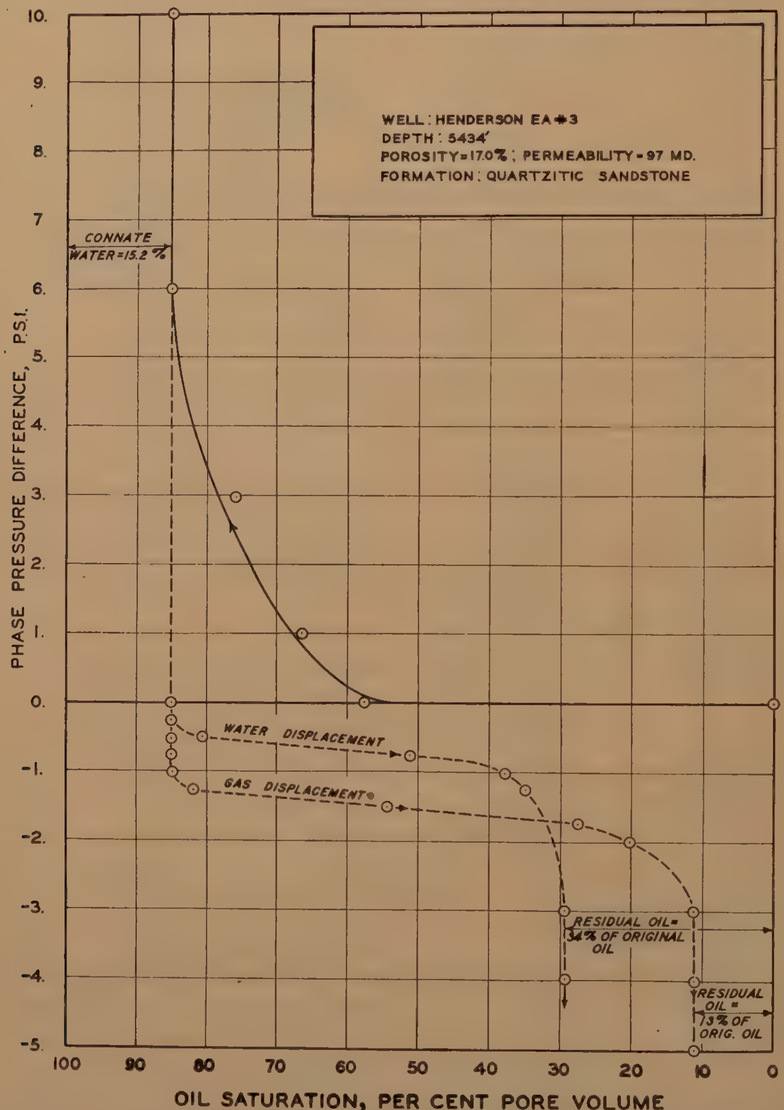

FIG 5—EXPERIMENTAL OIL PRODUCTION, ELK BASIN RESERVOIR, WYOMING.

Most of the limestone cores for which re-

sults are reported in Table 1 had been stored in contact with air for some years before use. Consequently, these pores may have been contaminated by oxidation products.

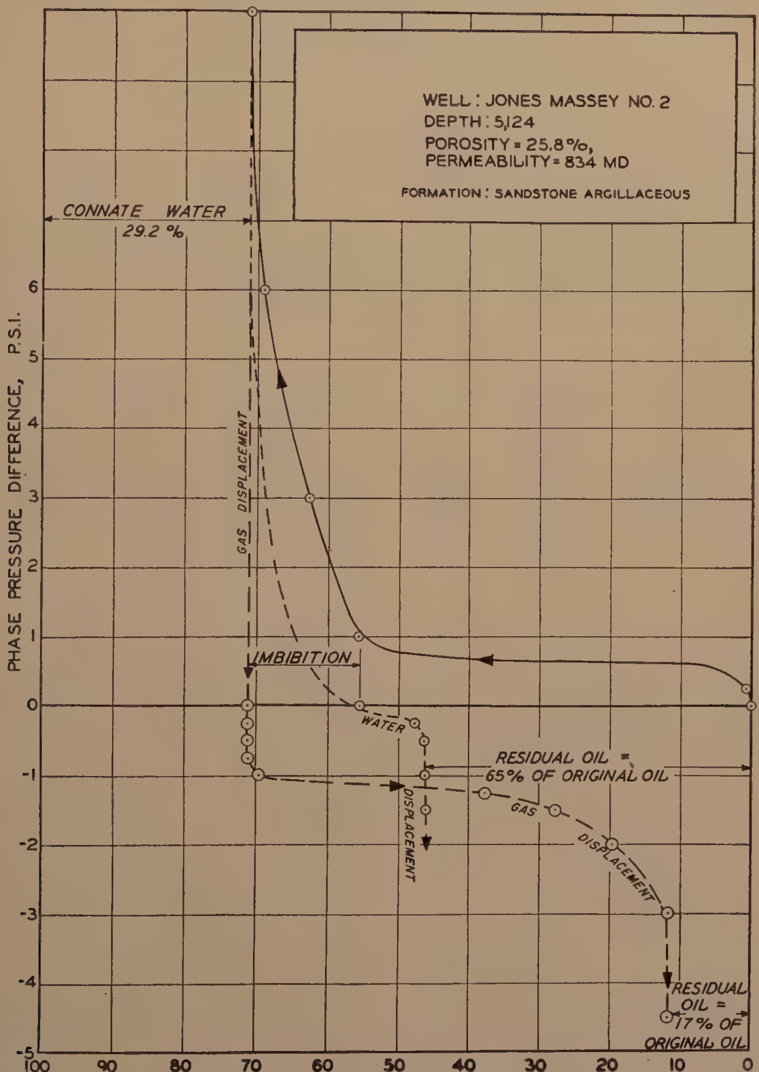

FIG 6—EXPERIMENTAL OIL PRODUCTION, PICKENS RESERVOIR, MISSISSIPPI.

The precision of the value obtained for maximum displacement suffers from the necessity of first establishing the original, restored-state saturation of oil and brine in any given core before the displacement of the oil can begin. Any error in establishing the restored-state condition might be expected to appear in the result obtained for ultimate recovery, in addition to error in the step involving the displacement of the oil. For these reasons two successive displacement results obtained under identical conditions with the same core may differ from

TABLE 1—*Maximum Oil Displaced by Water or Gas*

Reservoir and Lithology	Permeability, Millidarcys	Oil in Place Before Displacement, Per Cent of Pore Volume	Maximum Oil Displaced, Per Cent of Oil in Place		Residual Oil in Place after Displacement, Per Cent of Pore Volume	
			By Water	By Gas	By Water	By Gas
Magnolia (Arkansas)						
Oolitic limestone	2,882	78.6	77.2		17.9	
Oolitic limestone	623	72.8		81.6		14.1
Oolitic limestone	428	51.9	75.8	71.3	12.5	14.9
Oolitic limestone	113	67.3	70.9	78.5	19.6	14.5
Turner Valley (Alberta, Canada)						
Crystalline dolomite	12	93.5	91.5		7.9	
Crystalline dolomite	12	93.1	76.8		21.6	
Elk Basin (Wyoming)						
Quartzitic sandstone	541	90.5	81.0		17.2	
Quartzitic sandstone	470		88.8	82.6		
Quartzitic sandstone	248	79.7	88.5	89.7	9.2	8.2
Quartzitic sandstone	206	83.8	68.0	88.5	26.8	9.6
Quartzitic sandstone	133	77.7	51.3	94.0	37.8	4.7
Quartzitic sandstone	126	85.1	88.3	83.3	10.0	14.2
Quartzitic sandstone	47	76.7	45.5	82.6	41.8	13.3
Quartzitic sandstone	35	81.0	35.3	74.7	52.5	20.5
Pickens (Mississippi)						
Argillaceous sandstone	813	72.2	38.0	88.4	44.8	8.4
Agrillaceous sandstone	813	74.5	73.5		19.7	
Agrillaceous sandstone	612	69.4		80.6		13.5
Agrillaceous sandstone	379	57.8	64.8		20.3	
Agrillaceous sandstone	329	62.0	37.3		38.8	
Hawkins (Texas)						
Sandstone	4,100	78.3	61.6		30.1	
Sandstone	3,800	93.1	96.3		3.4	

one another by as much as 10 pct of the pore volume. Recent refinements in tech nique have improved somewhat the result- over some of the earlier ones reported is Table 1.

EFFECT OF VARIATION IN FLUID PROPERTIES ON THE MAXIMUM DISPLACEMENT

One object of the work in this section was to ascertain the extent to which the use of modified crude oil in capillary pressure experiments was justified. In order to study this problem, it was decided to use synthetic cores of alundum and of Pyrex glass. With these cores, it was unnecessary to remove residual organic material between runs by exhaustive Soxhlet extraction, since this cleaning could be done more quickly by heating the cores in air in a muffle furnace.

The removal of organic material was facilitated further by employing n-octane (B.P. 125°C) as the basic oil phase. The volatility of n-octane is low enough at room temperature to permit handling without significant loss through evaporation, yet high enough so that it can be expelled almost entirely by preliminary heating in a drying oven. The interfacial tension of the octane may be greatly reduced by adding a surface active, oil-soluble detergent. Sorbitol trioleate (Span 85, Hercules Powder Co.) is efficient in 0.5 pct solution, and leaves no residue on subsequent combustion. The viscosity of the oil phase was increased by the addition of refined mineral oil. The pH of the brine was adjusted by means of a dilute ammonium acetate-acetic acid buffer, which also leaves no residue on ignition. The interfacial tension and viscosity were varied 5 to 7 fold, because this much difference might be encountered between the properties of reservoir crude oil and the same oil at atmospheric temperature and pressure.

TABLE 2—*Displacement Results on Alundum Cores*

Core Number	Pore Volume, Cubic Centimeters	Porosity, Per Cent	Permeability, Millidarcys	Interfacial Tension, Dynes per Centimeter	Viscosity of Oil Phase, Centipoise	Connate Water, Per Cent	Octane Displaceable by Water, Per Cent of Original Octane	Residual Octane after Water Drive, Per Cent of Pore Volume
I	3.59	24.0	241	20[a]	0.5	22.6	65.2	26.9
I				3.8	0.5	24.2	74.5	19.3
I				3.8	0.5	19.5	76.0	19.3
II	3.47	23.4	191	20	0.5	26.2	74.4	18.9
II				3.8	0.5	21.7	73.6	20.6
II				20	3.5	23.2	61.0	30.0
II				20	3.5	21.6	70.3	23.3

[a] Measured by the pendant drop method.[6] This value is lower than the literature value (50 dynes per cm) for the n-octane-water interface, because of slight contamination of the octane with neoprene, Saran, and others. It is to be noted, however, that a considerable variation in tension was possible. Accordingly, it is believed that any significant effect of tension on ultimate displacement should have had the opportunity to manifest itself.

The data obtained on two similar alundum cores are given in Table 2. The results obtained by varying interfacial tension and viscosity, while not entirely conclusive, indicate that: (1) extreme variations in interfacial tension of a low viscosity oil does not produce a large effect on the minimum residual oil; that is, one greater than the precision obtained in duplicate runs, and (2) a 7-fold increase in viscosity produces, at most, only a small decrease in oil displacement. Further experiments will be needed to decide whether variations in fluid properties produce small observable effects or none at all.

It seems to be impossible to employ a gas, such as nitrogen or air, in place of the oil phase in the study of maximum displacement. Many cores when tested, even though dry initially, imbibed nearly 100 pct of their pore volume of water if given the opportunity. This result means that a corresponding volume of the gas originally present in a core could be displaced spontaneously by water. As will be noted from Tables 1 and 2, however, an oil phase cannot, in general, be displaced completely by brine, even though capillary pressure is applied. Therefore it would appear that there may be fundamental differences between the behavior of gas-water and oil-water interfaces in pores which preclude the substitution of either combination of fluids when displacement information is desired on the other combination.

TEST OF ACCURACY

The inference that laboratory results on maximum displacement are indicative of conditions existing in underground reservoirs has been justified in the case of connate water.[1] In the case of maximum displacement of oil, vindication looks toward two sources: (1) further laboratory work on altering fluid properties, including work with metal displacement cells and cellophane membranes capable of operation at or near reservoir temperature and pressure, and (2) verification, possibly through drilling or side-wall coring in flushed out areas, of the residual oil saturation. This saturation could then be checked against the residual oil remaining after laboratory displacement.

ACKNOWLEDGMENTS

The cores from the Turner Valley field in Alberta, Canada, were obtained through the courtesy of the Royalite Oil Company Ltd., and those from the Hawkins field through the courtesy of Humble Oil and Refining Company. The valuable assistance of Dr. W. A. Bruce in developing the theory of the capillary pressure technique is gratefully acknowledged. Miss Freida A. Jones aided in obtaining much of the data

reported. The author wishes to thank the management of the Carter Oil Company for permission to publish this paper.

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DISCUSSION

E. R. Brownscombe* and R. L. Slobod†—The author should be commended for this interesting paper. The extension of the capillary pressure technique to determine residual oil saturations is an important advance. The possibility of studying residual oil saturations under flowing conditions in which no phase barrier is used is alluded to by the author but no clear distinction between the implication of the flow method and the capillary method is made. We would like to discuss in a little more detail some differences between flow experiments and capillary pressure experiments of the type given in this paper. We are suggesting that these two displacement procedures be referred to as the *dynamic* method and *static* method, respectively.

In the laboratory two general methods may be used for displacing one phase with another. In one method a semipermeable membrane is used to restrain one fluid, allowing free passage to another so that a fixed pressure differential may be maintained between the phases. The saturation gradually readjusts until a static equilibrium is reached, no further flow occurring. We have referred to this as the *static* method of displacement. It is the one used by the author.

A second method of displacing one phase by another involves continuous flow. For example, if a core is saturated with water and oil flowed through the core continuously at a constant rate, a steady-state or dynamic equilibrium will be reached beyond which no change in saturation occurs although oil continues to flow through the core. Obviously, other initial conditions may be used and one or more flowing phases may be used. We have referred to this as the *dynamic* method of displacement.

Both methods may be used for displacement studies. The author deals with the static method. Dynamically, one may study conditions along a long core with appropriate flow rates and observe saturation for various pressure differences between the phases (keeping in mind the end effect). Our experience indicates that *static* and *dynamic* methods give different relationships between saturation, permeability, interphase pressure difference and residual saturation. Thus, Henderson and Yuster[7] noted that their (dynamic) irreducible water saturations were unaccountably high. Had they run irreducible water saturations statically instead of dynamically, we would expect their irreducible water saturations to be closer to field values. In this instance, in view of the static nature of equilibrium in the field during geologic time, the static method would appear to be more appropriate for this purpose.

On the other hand, the present paper deals with problems of field depletion. These problems may involve a complex mixture of static and dynamic types of displacement. The author speaks of relating hydrostatic head to (static) displacement saturations. Pressure gradients due to flow may give rise to pressure differences between the phases as great as those due to hydrostatic heads, and the passage of the displacing fluid through the reservoir may establish conditions more closely akin to those of dynamic laboratory experiments than to those of static ones. In any event, we believe that the fundamental nature of the differences between the static method used by the author and dynamic processes occurring in the reservoir depletion should be pointed out.

We believe that a clear differentiation in the procedures and implications of static and dynamic laboratory experiments would go far

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[7] Henderson and Yuster: *Producers Monthly*, (Jan. 1948) 19.

toward eliminating confusion in their application to field results.

W. A. HEATH*—Dr. Welge's experiments to determine the effects of capillary forces in displacement of oil from reservoir rocks are exceedingly interesting and commendable. The role of capillarity in fluid displacement has been discussed in articles on reservoir behavior for years, but until recently very little progress had been made in obtaining a quantitative measurement of such forces in actual reservoir formations. It is hoped that Dr. Welge's adaptation of the restored state apparatus will provide the means for quantitative evaluation of residual oil saturation obtainable under capillary control of reservoir production.

The author recognizes, and it should be emphasized, that the residual saturations obtained in the displacement apparatus are not a measure of the efficiency of water flooding and gas drive as applied in secondary recovery practice. Such methods involve the passage of the injected media horizontally through the sand. Capillary effects are generally directed vertically in the reservoir. In a producing reservoir both forces are in operation; the horizontal flow resulting from movement of fluid to the well bores due to pressure gradients and vertical forces resulting from disturbance of oil-water-gas phase equilibria and unequal pressure gradients in adjoining strata of varying permeability.

It will be observed that in a majority of the reported tests the displacement by gas resulted in lower residual oil saturations than displacement by water. This is contrary to the conceptions of water and gas recovery efficiency of horizontal flow based on limiting economic water- or gas-oil ratios. Dr. Welge mentions that the displacement tests are analagous to gas-cap gravity-drainage production of a homogeneous reservoir. The effect of gravity drainage may be greater than generally considered. In the case of the Oklahoma City Wilcox reservoir, gravity drainage was demonstrated to be quite effective,[8] however, such performance was thought to be peculiar to that particular reservoir which was preferentially wetted by oil and contained low connate water saturation.

In many other depleted reservoirs in which cores for evaluation of secondary recovery prospects have been obtained, gravity drainage effects have not been prominent, due possibly to non-homogeneity of the reservoir. Before deciding to operate a pool in such manner to give preference to gravity drainage rather than water encroachment, the homogeneity of the reservoir as well as the time element involved in gravity drainage should be checked thoroughly.

The residual oil saturations after capillary displacement by water exhibited in Table 1 vary widely for each formation except the Magnolia (Arkansas) oolitic limestone. The residuals of the Elk Basin sandstone vary from 9.2 to 52.5 pct of pore space. There does not seem to be any correlation of residual oil with permeability or with the water saturation. In horizontal flooding of oil-sand cores in flood pots, the residual oil content correlates roughly with water content of the sample and viscosity of the crude. The residual saturation values so obtained generally range from 15 to 25 pct of pore space. The highest average residual saturation value coming to the writer's attention was 45 pct. In this instance the oil viscosity was 250 centipoises and the water content 20 pct of pore space.

The displacement of oil by water in the restored state apparatus is suggested by Dr. Welge as being analagous to the vertical rise of water from a water table into the oil reservoir due to capillary forces. The encroachment of water into oil reservoirs probably follows laws of hydraulic flow rather than capillary attraction in a majority of cases. In hydraulic flow displacement tests performed in laboratory flood pot apparatus, it is necessary to pass water equivalent to several pore volumes of the core specimen through the core before the oil saturation is reduced to residual. For instance, in cores saturated with approximately 65 pct oil and 30 pct water, the passage of one pore volume of water yields approximately 65 pct of the ultimate recovery; 10 pore volumes, 82 pct; and 100 pore volumes, 98 pct. A comparison of the effectiveness of the hydraulic displacement mechanism versus the capillary displacement mechanism is advisable to furnish a basis for determining the proper method of operational control of reservoirs to realize the maximum ultimate recovery. In many pools the withdrawal rates may not be subject to suffi-

* Earlougher Engineering, Tulsa, Oklahoma.

[8] Donald L. Katz: Possibilities of Secondary Recovery for the Oklahoma City Wilcox Sand. *Trans.* AIME (1942) 146, 28–49.

cient variation because of economic considerations to permit a change in displacement mechanism. A comparison of the two mechanisms might be made in the laboratory by taking samples which have attained their maximum capillary displacement in the restored state apparatus and subjecting them to hydraulic flow to determine whether the residual saturation can be further reduced.

P. P. REICHERTZ*—The results presented in this article are of considerable theoretical importance and the experimental work was obviously carefully done. However, certain academic considerations involved are, in the opinion of the writer, open to some debate.

Fundamentally, the question lies in the overall applicability of capillary pressure phenomena. The equation used in applying the results of capillary pressure studies to reservoir conditions is

$$\Delta p = g\Delta h\,(\rho_o - \rho_w)$$

where Δp = capillary pressure in dynes/cm^2
g = acceleration of gravity in cm/sec^2
Δh = height above water table in cm
ρ_o = density of oil in gm/cm^3
ρ_w = density of water in gm/cm^3

This equation can be derived only for conditions in which both oil and water phases are continuous throughout the portion of the porous medium being considered. In any reservoir, at least partial continuity of the water phase is assured by the finite resistivity of the oil sand, as determined by electric logs. However, the oil-phase continuity is assumed since there is no physical way to be certain that it is a continuous phase in all cases. It should be recognized that the continuity of the water phase does not imply similar continuity of the oil phase. Either one may be continuous and the other be discontinuous, as for example, in the two cases of oil-in-water emulsions and water-in-oil emulsions. However, it is probably safe to assume continuity of both phases in the reservoir.

Consideration of laboratory capillary pressure experiments which attempt to simulate these phenomena leads to the conclusion that continuity of both phases must also be assured in this case. In general, reservoir sands are assumed to be hydrophillic. This surface property of most quartzitic sandstones is probably sufficient to assure a continuous water phase during the course of a capillary pressure experiment and the manner of application of pressure to the oil phase gives reasonable assurance of its phase continuity. Hence, for this particular case, a true capillary pressure experiment results. However, if a lyophillic core is used, the picture changes. Since the water no longer has a continuous surface on which to reside as it did previously, water-phase continuity cannot be assured during the course of the whole experiment. It seems possible, therefore, that the end water saturation may represent the point at which the water phase becomes discontinuous rather than being a true measurement of a capillary pressure phenomenon. Resistivity measurements would be a check on this condition and it would be interesting if such measurements were available.

If the above discussion has any basis in fact, it becomes difficult to ascribe the results of the experiments in this paper to capillary pressure phenomena, in the particular case in which oil saturation is being determined by water displacement and the core surface is hydrophillic. As in the case previously described, the residual oil would likely be a measure of the saturation at which the oil phase became discontinuous, rather than representing a saturation dependent on capillary pressure phenomena. In the case of a lyophillic core, a true capillary pressure result would be expected, but the initial water-oil saturations, in this case, would be in doubt due to similar phenomena occurring during the initial interstitial water experiment. Certain of the results presented in this paper support these contentions. The lower residual oil saturations obtained using gas as the displacing fluid may obviously be explained on the basis that there is a continuous oil phase in these cases. In addition, Fig 5 shows that for a lyophillic core, and using water displacement, the residual oil saturation is 34 pct of the original oil in place and only 21 pct higher than the value obtained using gas. If the expected error in each determination (i.e. gas and water displacement) is 10 pct, these values are in partial agreement. However, in the case of a hydrophillic core, (as shown in Fig 6) the residual oil after water displacement is 65 pct of the original oil as compared with 17 pct for gas displacement. The "efficiency" of the water

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displacement mechanism in these two cases is markedly different and is in such a direction that the analysis given in this discussion will qualitatively explain the results.

It would be desirable, if appropriate data were available, to analyze more of the data given in Table 1 of the paper, on this basis.

These comments are not intended to imply criticism of the work, but merely to offer a possible explanation of results which, in some respects, seem to contradict previous evidence on the relative efficiency of gas and water drives (dynamic mechanisms) in producing oil from porous media.

H. J. Welge (author's reply)—The author is in agreement with Messrs. Brownscombe and Slobod regarding their definitions of dynamic and static conditions of oil displacement and regarding the statement that these two phenomena are basically different. It is very likely, however, that the results obtained from static tests of the type described in this paper together with other measurable quantities, such as permeability, porosity, viscosity, and interfacial tension can be used to predict what will happen in the case of a dynamic flow test. Thus it can be stated that there may exist relationships between the results of a static experiment and dynamic experiments, so that it may not be necessary to run a laboratory experiment exactly as the field will be exploited in order to predict its behavior.

The limited reliable information on fractional recoveries available to the author indicates that the static experiment referred to above will lead to the lower limit of residual oil left after the most advantageous displacement conditions possible have been established. In a number of pools the water table rises very gradually and in a broad sense uniformly, many of the rates of rise being only a few feet per year. In such a case the static experiment may very well be expected to reflect the upper limit of the amount of oil to be obtained by the most efficient exploitation of this type of reservoir.

Further, if the difference in density between the oil and water is high and if wells are completed and controlled in such a way as to minimize by-passing, the ultimate recovery from such a reservoir may conceivably approach the upper limit indicated by the static experiment described above.

In regard to Mr. Heath's comment, he is correct that the author recognizes the difference between the static experiment described in this paper and the problems of horizontal water flooding or gas cycling. The reason for this difference is very aptly stated in the comment by Messrs. Brownscombe and Slobod. It seems also to follow that the flood-pot experiments are not necessarily indicative of the recovery to be obtained from horizontal water-flooding operations, since the rates in the reservoir are extremely variable because of the radial flow nature of the problem. No flood-pot experiment can be expected to yield answers which will be applicable at all points in the system.

The S.P. Log: Theoretical Analysis and Principles of Interpretation

By H. G. Doll,* Member AIME

(New York Meeting, February 1948)

Abstract

The S.P. log is shown to be a measurement of the potential drop along the drill hole, caused by ohmic effect in the mud. The notion of static S.P. is brought forward, and its relation to the S.P. log is discussed. Other factors influencing the shape and amplitude of the log are considered; attention is given to conditions encountered in practice. Numerous figures are given illustrating graphically the results; these figures are of particular interest for comparison with field examples.

The S.P. log, although indicating permeability, is not an absolute measurement of permeability, nor of porosity, of the formations traversed by a drill hole. It is affected by several parameters, such as resistivity of formations and mud, thickness of formations, and others, which should be appraised carefully. Simple rules have been established for a better distinction of the boundaries of permeable sections, particularly in difficult cases, such as those encountered in highly resistive formations. A systematic application of the established principles will assist in obtaining more information from the S.P. log than was possible thus far; for instance, under favorable conditions, presence of oil may be detected, or amount of shale in sands may be estimated.

Introduction

The S.P. log, or spontaneous potential log, has been known and widely used during the last 15 years for the location of permeable† beds traversed by drill holes.[1,2]

In electrical logging practice, the S.P. log is shown on the left hand side track of the record (as may be seen in later examples) where it can be easily correlated and interpreted with the resistivity curves located to the right. Usually, the S.P. log consists of a base line, more or less straight, having excursions or "peaks" to the left. The base line frequently has been found to correspond to impervious beds, while the peaks are usually found opposite permeable strata.

Measurements which will indicate positively the presence of permeability in the formations, and which will give accurately the boundaries of the permeable zones, are of great importance in oil-field practice. Thus far, the S.P. log is the best approach to such determinations; unfortunately, its interpretation is not always evident.

With respect to the base line of the S.P. log, it may be noticed that this line is not always at a definite location on the chart. Sometimes it may shift abruptly, while other times a gradual drift is apparent.

As far as the peaks are concerned, their shape is not uniform; some are rounded while others are sharp. Also, from other data, it may be found that occasionally the peaks extend appreciably beyond the boundaries of permeable zones into zones which are not everywhere permeable.

A comparison with permeability measurements made on cores has often confirmed that there was no definite correspondence between the magnitudes of the peaks and the permeability values. In the same geological horizon, it generally will be found that most of the thick and permeable for-

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† Throughout the paper, the term permeable is used in a broad sense to qualify all media which may pass fluid, even though their permeability might be too low for production requirements.

[1] References are at the end of the paper.

mations exhibit peaks on the S.P. log that have about the same magnitude, although the permeability is variable. On the other hand, thin formations of comparable permeability may show peaks having different magnitudes.

There has been a desire to derive from the S.P. log information such as quantitative permeability or porosity. Since the log is unable to supply this quantitative information, a certain confusion has been created about the real meaning of the S.P. log. As a result, it is not always interpreted with complete efficiency, particularly when holes are drilled through hard formations.

There is no doubt that the shape of the S.P. log, as well as the magnitude of its deflections, are affected by conditions other than the permeability of the formations. In order to improve the interpretation of the log, an attempt will be made in this paper to explain the conditions responsible for its shape. It will be shown that, among other things, the thickness of beds, as well as their resistivity, have an important bearing on the S.P. log. A discussion concerning the emf (electromotive force or forces), which produce the potential differences measured on the log, will be given. In addition, numerous examples of typical cases, most of them computed with good accuracy, will be shown, thus constituting a sort of catalogue which should enable the reader to make a better use of the S.P. logs recorded in actual field practice. A few simple rules will also be given to improve further the interpretation, especially for determining the boundaries of permeable beds.

Technique of S.P. Logging

The recording of S.P. logs is made according to a simple technique. As illustrated in Fig 1, an electrode *M*, located at the end of an insulated cable *C*, is moved up or down in the mud filling the drill hole. The cable passes over a calibrated sheave *S*, and is wound on a winch *W*. Contact with the insulated conductor is established through a slip-ring collector *SR*, which is connected to one terminal of a recording galvanometer *R*; the other terminal of the galvanometer is connected to a potentiometric circuit *P*, and then to an electrode *N*, usually placed in the mud pit or attached to the casing of the hole.

The movement of the sensitive paper or film in the recorder *R* is synchronized with the movement of the electrode *M* along the drill hole. The depth scales used in recording are 1 in., 2 in., and 5 in. per 100 ft of electrode motion. The recorder registers a log on which the abscissas are proportional to the depth of electrode *M*, and the ordinates represent the potential of electrode *M* with reference to electrode *N*.

The drill holes in which the S.P. logs are recorded are usually filled with mud having a water base. The mud density is such that at each depth the hydrostatic pressure in the hole is greater than in the formations; as a result, the fluid contained in the permeable beds cannot contaminate the mud. Also, the mud is in constant circulation during the drilling operation, prior to the logging, and therefore it is homogeneous.

According to the circuit shown on Fig 1, it can be seen that the recording galvanometer *R* measures all the differences of potential appearing between electrodes *M* and *N*. However, provided some proper precautions are taken, experience has shown that under usual conditions the deflections on the S.P. log correspond to phenomena occurring at the contacts between the mud and the different beds, and also at the contacts between the beds themselves. These phenomena produce an electric current, called "S.P. current,"* which uses the mud as its return path. In so doing, it creates in the mud by ohmic effect, potential differences which can be measured and

* The expression "S.P. current" may seem rather illogical as S.P. stands for "spontaneous potential"; however, as it has definitely passed in common use, the author thought it preferable to keep it.

plotted versus corresponding depths, to constitute the S.P. log.

Other sources of potential, which are not related to the formations, do not usually cause any deflection on the S.P. log; if present and bothersome, proper steps are taken to overcome them. Particularly, electrodes M and N are chosen to be stable insofar as their contact potential with the mud is concerned; in practice, M and N are lead electrodes. A constant difference of potential may normally appear between these two electrodes in the absence of any S.P. current. This difference of potential is not recorded on the S.P. log; it is counterbalanced by means of the potentiometric circuit P.

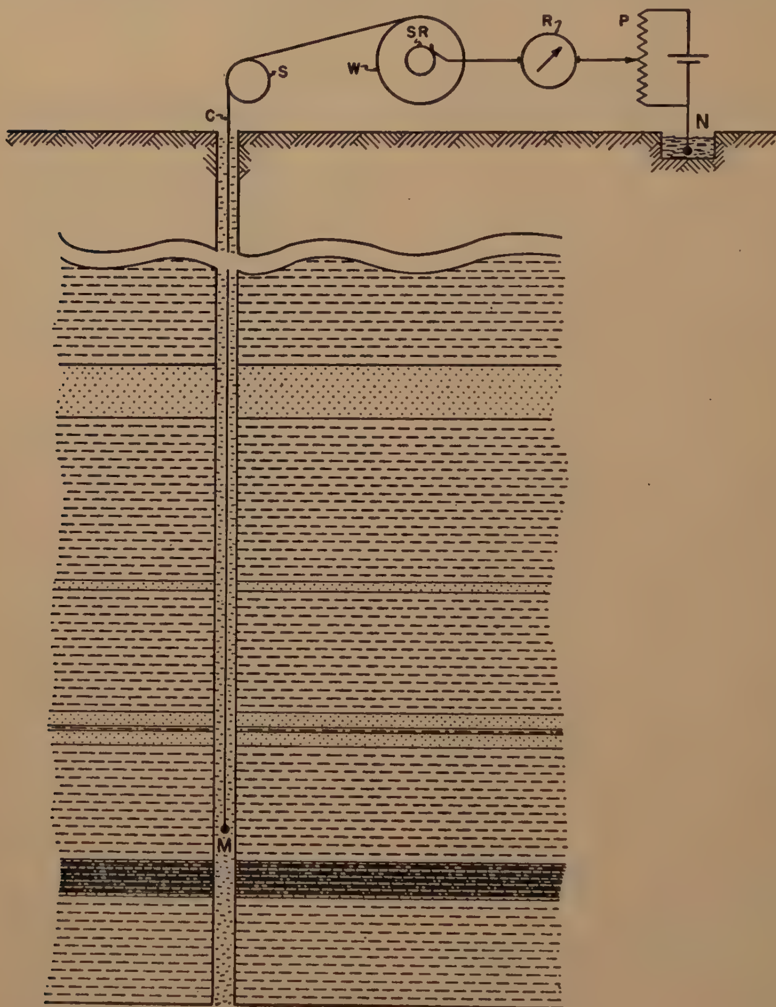


FIG 1—SCHEMATIC CIRCUIT FOR RECORDING S.P. LOGS.

Accordingly, the potential of electrode M is measured on the S.P. log with reference to an arbitrary constant. However, the variations of the potential, that is, the deflections on the S.P. log, do not depend

on the arbitrary constant, and they measure the potential differences as created in the mud by the S.P. current. These deflections make it possible to characterize the formations. Under normal conditions, the excursions toward the negative characterize permeable beds, while excursions toward the positive characterize impervious beds.*

Electromotive Forces—the Static S.P. Diagram and Its Relation to the S.P. Log

The emf generating the S.P. current, which affects the S.P. log, arise from two types of phenomena. The first one is of electrokinetic nature, producing an emf of filtration[1] at the contact drilling mud-permeable bed. Since the hydrostatic pressure of the mud in the drill hole is greater than the pressure in the permeable formation, some mud fluid filtrates slowly through the mud cake into the permeable bed. This causes an emf to appear, primarily where the pressure difference is maximum, that is, across the mud cake. The emf depends on the nature of the filtrate and of the filter (mud fluid and mud cake), and on the pressure difference. As a result, for a given formation, the emf will be uniform all along the contact mud-permeable bed. If the difference in pressure is about the same for various permeable formations traversed by a drill hole, the emf of filtration will also be the same.

The second phenomenon is an electrochemical one. It occurs at the contact of media of different nature, and creates an emf at each such contact.† For instance, referring to Fig 2*a* and *b*, there are three contacts or boundaries shown at *A*, *B* and *C* as follows:

A = boundary between mud and salt-water sand,*

B = boundary between salt-water sand and clay,

C = boundary between clay and mud.

An emf of an electrochemical origin exists at each of the boundaries, *A*, *B*, *C*. As each medium is fairly homogeneous, each emf is uniform along the corresponding boundary.

At the boundary *A*, an electrokinetic phenomenon as well as an electrochemical one is present; thus, there is an emf corresponding to the algebraic sum of two forces of different origin.

In order to get a better understanding of the effect of the emf, it is convenient to consider first an idealized case where the S.P. currents are prevented from flowing. In this connection, Fig 2*a* represents a drill-hole section that traverses two identical thick beds of clay separated by a rather thin salt-water sand. Although this would not be easily feasible in practice, it may be conceived that two insulating plugs are placed in the hole to interrupt the electrical continuity of the mud column at the two boundaries between sand and clay.

The presence of the plugs does not affect the emf; at the boundaries *A*, *B*, and *C* there are emf designated respectively by *a*, *b*, and *c*. Since the plugs prevent any current flow, the potential within each single medium, enclosed by boundaries or plugs, is then constant. However, the potential varies from medium to medium, the difference of potential between two adjacent media being equal to the emf existing at their common boundary.

Considering that the emf, *a*, *b*, and *c*, are positive in the direction shown by the small arrows, and designating by V_o the po-

* The polarity of the excursions might be reversed in certain cases, and in particular when the salinity of the mud is higher than the salinity of the water in the permeable beds.

† It should be remarked that the presence of a clay or shale bed adjacent to a permeable formation has a definite bearing on the value of the electrochemical emf. This was noticed by Conrad Schlumberger and reported in a paper[2] in 1933. Later on, Mounce and Rust elaborated on this matter and discussed their findings.[3] Also, Dickey[4] investigated the question of potentials appearing in drill holes and open shaft.

* For simplification, it is assumed that there is no appreciable invasion in the permeable formation. The effect of invasion will be examined in a later section.

tential of the mud in the section above the upper plug, the potential in each medium is as indicated in the corresponding boxes on Fig 2*a*. These potentials are determined

In the salt-water sand: $V_o - c - b$.

In the mud section comprised between the plugs: $V_o - c - b - a$.

In the lower clay bed: $V_o - c$.

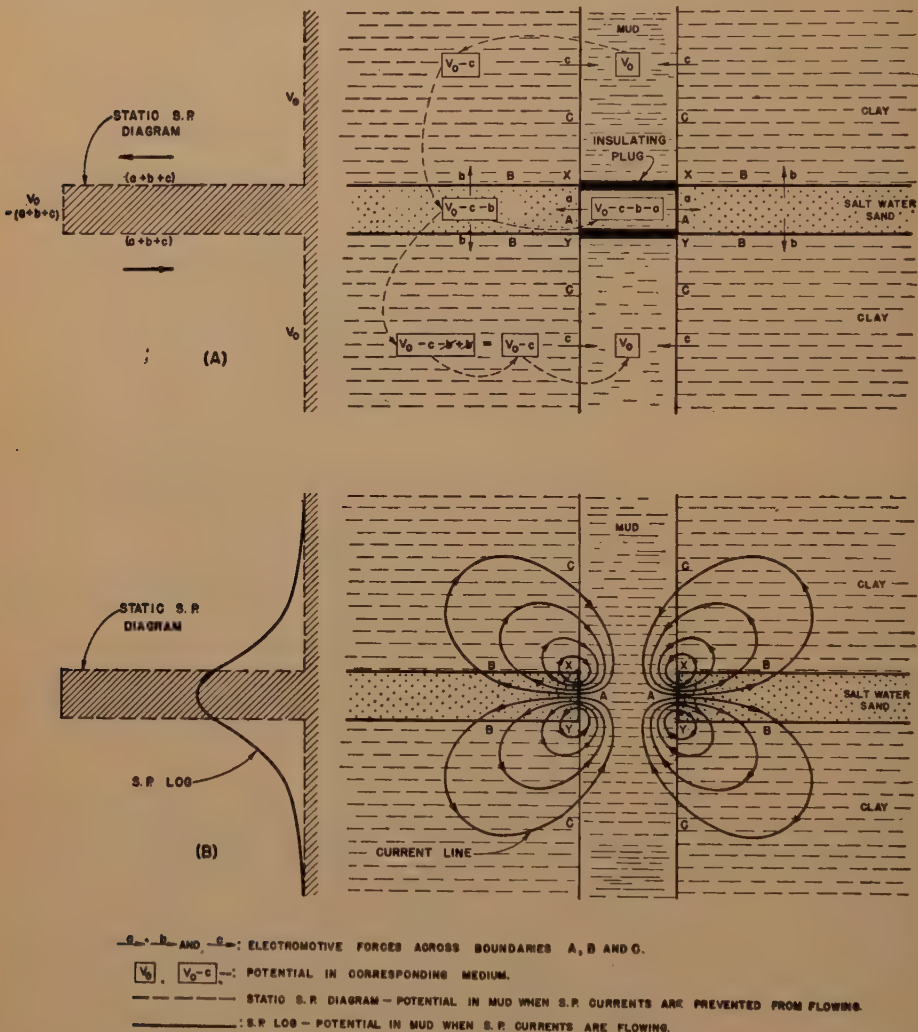


FIG 2—SCHEMATIC REPRESENTATION OF POTENTIAL AND CURRENT DISTRIBUTION IN AND AROUND A PERMEABLE BED.

by algebraic addition of the potentials encountered when going from one medium to the next. The values of the potentials are as follows:

In the upper section of the mud: V_o.

In the upper clay bed: $V_o - c$.

In the lower section of the mud: V_o.

From the point of view of the S.P. log, it is, of course, essentially the potentials in the different sections of the mud which are of interest. In that respect, it is very important to remark that the potential of the

mud section in front of the lower clay is the same as in the upper section. It is also fundamental to observe that the potential of the mud in front of the sand differs from the potential V_0 in front of the clays by the quantity $(a + b + c)$, which is the sum of the emf of the 3 boundarys, a, b, and c.

At this point it is pertinent to remark that the boundary emf show their effect through a combination of 3 values. Furthermore, the existence of 3 boundaries having a common junction is quite fundamental in the analysis of S.P. logs; they constitute a triad which will appear in further discussions. The combination of 3 emf at the boundaries, along any closed path traversing all three media, establishes what is conveniently called a "3-link chain emf."

The left part of Fig 2*a* represents a diagram which can be considered as the S.P. log for this idealized case. On this diagram the potential in the mud is plotted versus depth. As it corresponds to the case where no current is flowing, or in other words to a static case, it will be designated hereafter as the "static S.P. diagram."*

Although a purely theoretical concept, the static S.P. diagram is of great interest. It represents, in a convenient manner, the values of the emf which produce the S.P. currents, and which therefore determine the S.P. log.

Going over to Fig 2*b*, it will be seen that the figure represents the same schematical example as Fig 2*a*, except that the insulating plugs have been removed to re-establish the continuity of the mud column. In these conditions, there is no longer a static equilibrium, but rather a dynamic state. The S.P. current can flow in the drill hole through the mud, as well as in the formations.

The 3 emf, a, b, and c, add their effects to generate the S.P. current which follows the paths represented on Fig 2*b* by solid lines. Each line corresponds to a line of flow, the current circulating in the direction of the arrows.

Each current line must necessarily cross the three boundaries A, B, and C. Furthermore, that part of the current generated by each of the 3 emf, a, b, and c, follows the same path; the current lines are independent of the repartition of the emf between the 3 boundaries. In other words, the intensity of the current circulating in the mud of the drill hole depends only upon the algebraic sum of all the partial emf in the circuit, and does not depend upon the allocation of these partial emf to each boundary, provided that each emf is uniform everywhere on its corresponding boundary.

Along its path, the S.P. current has to force its way through a series of resistances, both in the ground and in the mud. In so doing, it produces potential differences according to Ohm's law. Along a given line of flow, the potential falls down continuously in the direction of the current, as indicated by arrows, but at each boundary where an emf occurs, the potential is raised by an amount corresponding to the value of the emf. Along a closed line of current flow, the total drop of potential is necessarily equal to the sum of the emf encountered.

Also, the intensity of the current being constant along its path, the potential drop varies according to the resistance of the section through which it flows. This means that the total potential drop (which is equal to the sum of the emf), is divided between the different formations and the mud in proportion to the resistances respectively encountered by the current in each medium. Accordingly, the potential drop in the mud of the drill hole measures only part of the total emf, unless the electrical resistance offered by the mud is very large compared to the one in the formations.

The S.P. log records the potential drop occurring in the mud. It follows that the amplitude of the peak of the S.P. log ap-

* The word diagram, rather than log, is used here to insist on the fact that this curve is of hypothetical nature and is not actually logged.

proaches the amplitude of the static S.P., which is the sum of the partial emf, only in favorable cases. When the resistance of the mud to the flow of S.P. current is not large compared to the resistance in the formations, then the S.P. log will show a peak of lesser amplitude than the static S.P. diagram.

It may also be seen on Fig *2b* that the current circulates in the mud, not only opposite the permeable formation (salt-water sand), but also part way beyond the boundaries of the formation. As a result, though the static S.P. diagram indicates a sharp break corresponding to the boundaries of the permeable bed, the S.P. log exhibits a more progressive change in potential, extending along the drill hole beyond the boundaries of that bed.

In the case illustrated by Fig *2b*, the permeable bed is thin, so the resistance in that bed is appreciable compared to the total resistance in the S.P. current path. This is why, in that case, the deflection of the S.P. log, which measures the potential drop in the mud, is only a fraction of the total emf. To make that point clearer, the S.P. log has been represented in solid line, together with the static S.P. diagram whose deflection characterizes the total emf involved.

As shown by the figure, the deflection of the S.P. log is not only smaller than the one of the static S.P. diagram, but it is also much more progressive. It is interesting to note that the slope of the S.P. log measures the potential drop per unit length in the hole, which is proportional to the intensity of the S.P. current in the mud at the corresponding level. Starting from the top part of the log and going down, the slope increases progressively because the current in the hole increases progressively, until the level X (contact clay-sand) is reached. At that level, the intensity of the current in the hole is maximum, and this corresponds on the S.P. log to a maximum slope, or in other words, to an inflection point. Below that level, the current progressively decreases until it becomes nil in the middle of the sand; this corresponds to the point of maximum deflection. Farther down, the current flows in the opposite direction, so that the slope of the S.P. log is reversed. That slope increases progressively, until a new maximum is reached at the level Y (lower sand-clay contact), which corresponds to another inflection point on the S.P. log; and still farther down, the slope progressively decreases again because the current itself decreases.

The above remark about the inflection points of the S.P. log is important for their interpretation. There has sometimes been a tendency to place the boundary between a permeable and an impervious bed at the point which corresponds to half deflection on the S.P. log. This can be substantially wrong in certain cases. The contact level should be taken as corresponding to the inflection point on the S.P. log.

The Shape and Amplitude of the S.P. Log—Influence of Various Factors

The shape and amplitude of the peak on the log opposite a given bed may be influenced by the following factors: (1) the total emf involved; (2) the thickness of the bed; (3) the resistivity of the bed, of the surrounding formations, and of the mud; (4) the diameter of the drill hole; and (5) the depth of penetration of the mud filtrate in the permeable beds.

Where the permeable beds contain some impervious and conductive material, such as shale, the S.P. log may also be affected by the presence of that material. This subject will be discussed in the section on shaly sands.

The S.P. log would be influenced additionally by a lack of homogeneity in the mud; a change in salinity of the mud at a certain level would result in a base-line shift at that level. However, it has been

found in practice that such change in salinity is very seldom encountered.

In the text, the expression "impervious bed" or "impervious formation" is always used to designate formations like, for example, shale or clay, which are at the same time impervious and porous. As they contain water, they are also conductive. On the figures such beds are identified by the letter *C* followed by an index number which refers to the particular bed concerned. Compact or hard formations which contain extremely little water, and have no permeability, are designated by the expression "hard formation" and are identified on the figures by the letter *H* with corresponding index number. Finally, formations like sands, porous limestone and the like, which are permeable —even though the permeability might be very low—are designated by the expression "permeable bed," or "permeable formation," and they are identified on the figures by the letter *P* followed by the corresponding index number.

The theoretical figures, which illustrate the effect of the various factors on the S.P. log, have been drawn to correspond to field conditions as closely as possible. Each figure shows the geological cross section, the drill hole, the S.P. log and the static S.P. diagram. Resistivity values are indicated by numbers in circles, in units of mud resistivity. To facilitate a comparison between the examples and field logs, the thickness of formations, size of drill hole, and depth of mud invasion have been represented at the same dimension scale for each figure. Furthermore, the amplitude of the deflection on the static S.P. diagram and on the S.P. log has been plotted to have the same ratio to the dimension scale as the ratio used for logs recorded in the field at 5 in. per 100 ft. The maximum potential deflection has been indicated as corresponding to 100 mv for convenient comparison.

Unless otherwise specified, all the examples given in the following paragraphs have been computed mathematically. In this connection, each medium is considered homogeneous and isotropic. When an accurate computation was not possible, approximations were made, and this fact is mentioned on the corresponding figures by the word "schematic" in the caption.

Influence of the Electromotive Forces

All other factors remaining the same, a change of the total emf affects the amplitude but does not otherwise modify the shape of the S.P. log. A change of the emf at the different levels in a drill hole, by the same proportion, is equivalent, as far as the S.P. log is concerned, to a change in the millivolt scale, or, in other words, in the sensitivity of the recording galvanometer.

In practice, the emf involved may vary from one hole to another, either because the salinity of the mud, or of the formations, is quite different, or, to a smaller extent, because the differential pressure between the mud and the formations is different. In a given hole, however, and for the same type of formations and depth, there is a definite tendency for the total emf to be the same for all beds of the same type. This is clearly shown by logs taken in formations consisting of thick and conductive impervious beds, and thick permeable beds. In front of the former, the S.P. log gives a good, straight base line, while the peaks corresponding to the latter have generally the same value, which implies that the emf are the same for all of them. True enough, there may also be a certain number of thin permeable beds which give on the S.P. log peaks of smaller amplitude. Conversely, there might be, within thick permeable formations, thin impervious beds for which the S.P. log does not come back to the base line. But this effect of the thin beds can be explained by other causes, as will be shown hereafter, and there is therefore no reason to assume that they produce smaller emf. On the contrary, the fact that there is a good base line shows that all conductive

impervious beds are of much the same nature, while the fact that all large peaks are of the same amplitude shows that salinity and differential pressure are the same for all thick permeable beds. Then, in all probability, these conditions should be the same for the thinner beds in between, and it is quite logical to look for other factors, and in particular for the thickness, to explain the smaller deflections observed.

Permeable beds of different porosity, or with different dimension of grains, give the same emf, if other factors are unchanged. The emf are also independent of the permeability value, even down to fractions of one millidarcy.

The electrochemical emf depend only on the salinity of the permeable beds, on the nature of the impervious formation with which they are in contact, and on the nature of the mud, while the electrofiltration emf depends only on the differential pressure and on the nature of the mud, which itself determines the mud cake where that emf is generated.

It has been observed that the salinity and the differential pressure are not always constant for all permeable beds, especially at widely different depths or in very different formations. Fresh water sands or very salty sands will show respectively abnormally low or large amplitude of peaks. The polarity of the peak even reverses if the sand is less salty than the mud. Depleted sands, where the pressure is very low, give peaks of large amplitude, especially with muds of very low salinity which favor the electrofiltration emf. Such changes in salinity and pressure produce changes of the emf. Generally these can be detected without too much difficulty in the thick permeable beds because the amplitude of the peaks on the S.P. log for the thick beds is equal to the total emf. In the thin beds, for which the peak amplitude on the S.P. log depends, as will be shown later, on the thickness and the resistivity, it is practically impossible to separate the effect of the different factors on the S.P. log, and, therefore, to evaluate the emf.

Certain muds of special chemical composition have the property of reversing the polarity of the emf. In such cases, the S.P. log excursions will be reversed and the permeable sections will correspond to positive excursions.

In the remainder of the paper, the total emf, which is responsible for the different peaks on the S.P. log, is assumed to be of equal value. This assumption is represented on the figures by the fact that all deflections are of the same amplitude on the static S.P. diagram. Consequently, the amplitude of all peaks on the S.P. logs should be the same, were it not for other factors whose effects appear as differences between the S.P. logs and the corresponding static S.P. diagrams.

The above hypothesis of a constant total emf for the static S.P. diagram, although apparently made only to assist in the description of the figures, is in fact, very often conformed to by the actual field conditions. This is particularly true, as already mentioned, in the case of a long section of sand and shale formations, when the following requirements are satisfied: (1) all shales are of similar nature; (2) the salinity of the connate water in all sands is nearly the same and; (3) the differential pressure across the mud cake is the same for all sands.

These conditions, for example, are quite well satisfied in the Gulf Coast area in the Frio formations, which are many thousands of feet thick—the shales give a very good base line, while the salinity of the sands varies only from 35,000 to 65,000 ppm.

Influence of the Thickness of Beds

In this section the resistivity of all beds is chosen to be the same and is equal to the resistivity of the mud. This case is not as theoretical as it may appear to be; it occurs rather frequently, in the Gulf Coast area

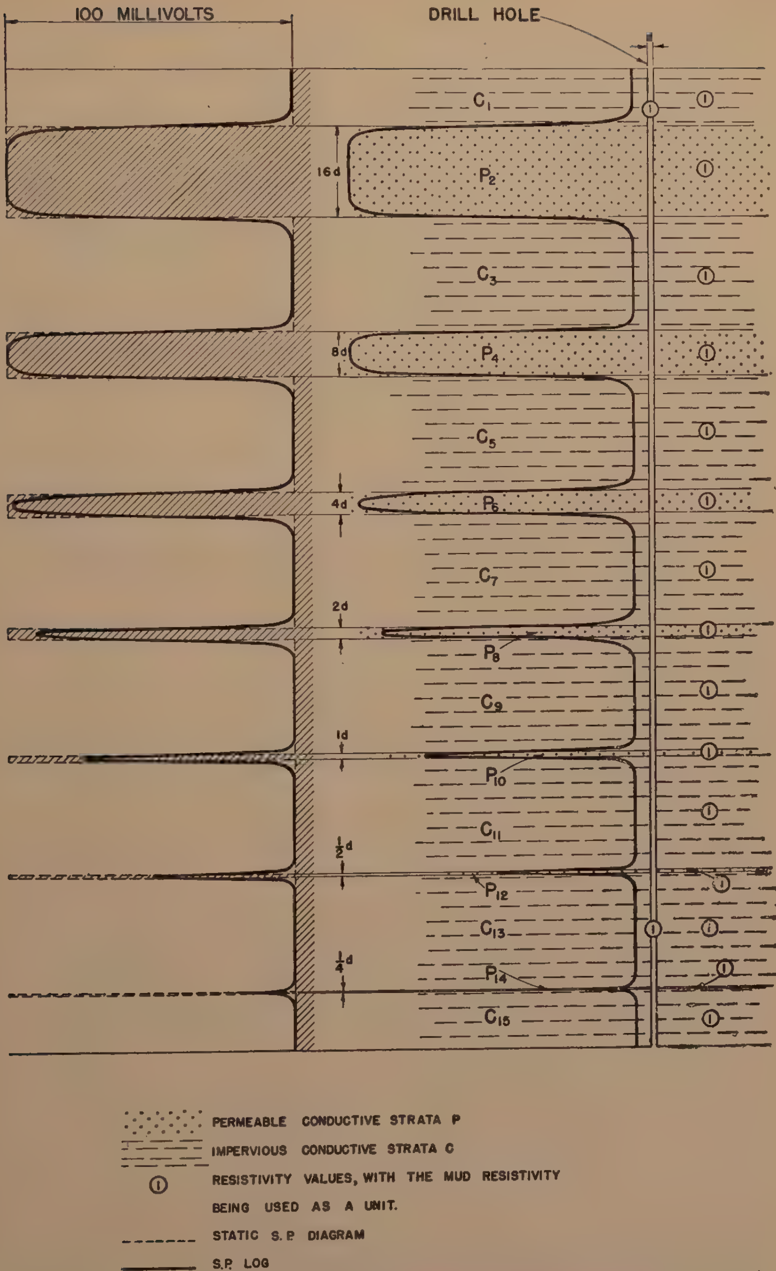


FIG 3—S.P. LOG FOR DIFFERENT THICKNESSES OF PERMEABLE BEDS ($R_t = R_m$).

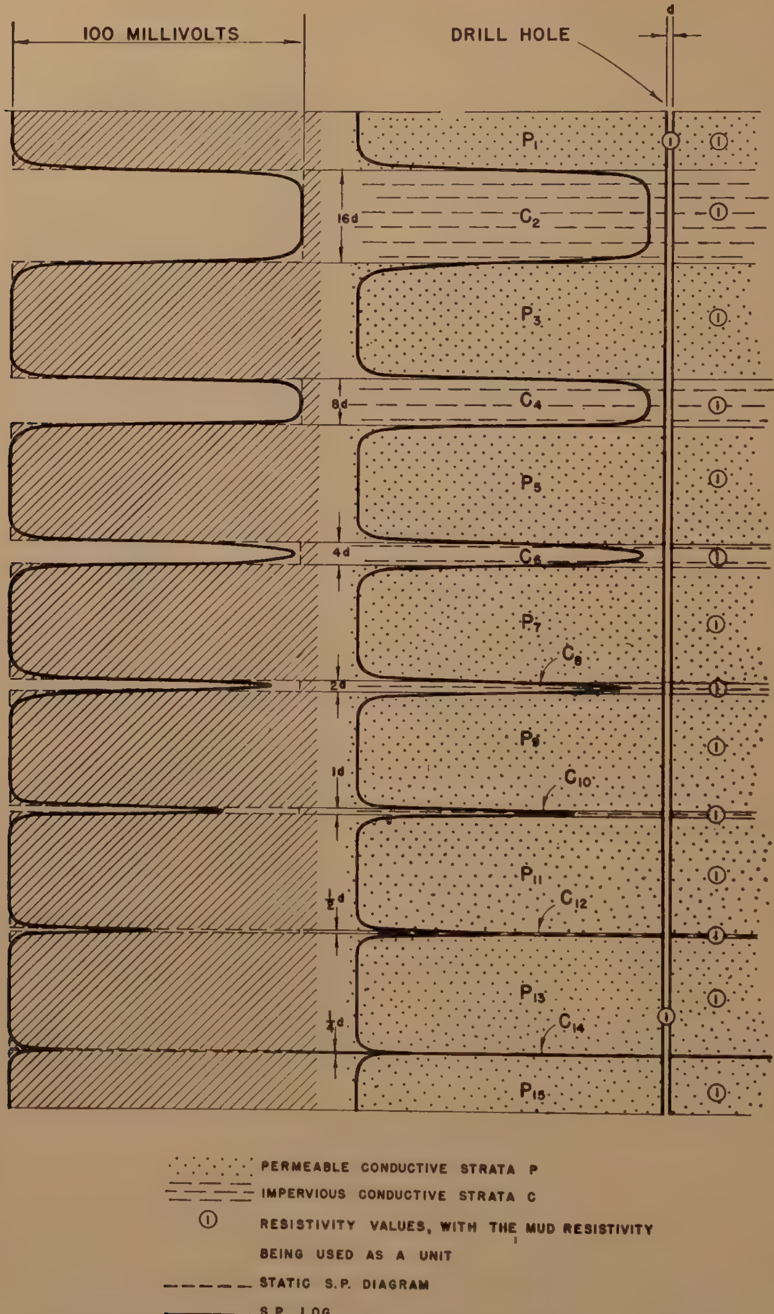


FIG 4—S.P. LOG FOR DIFFERENT THICKNESSES OF IMPERVIOUS BEDS IN A THICK PERMEABLE STRATUM ($R_t = R_m$).

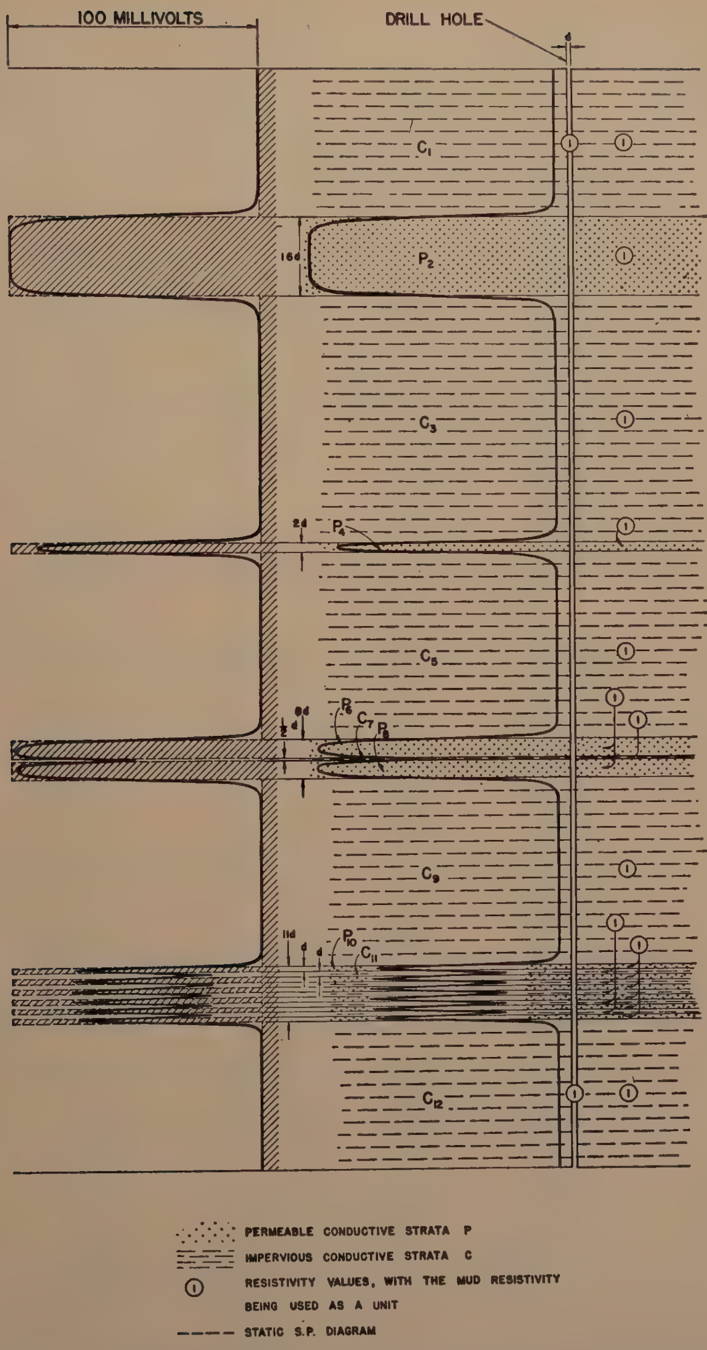


FIG 5—S.P. LOG FOR VARIOUS COMBINATIONS OF PERMEABLE AND IMPERVIOUS BEDS ($R_t = R_m$).

for example, when formations of shales and salt-water sands are traversed by drill holes containing natural mud. Figs 3, 4, and 5 illustrate the effect of bed thickness on the S.P. log.

Fig 3 represents a succession of salt-water sands separated by thick layers of shales. In this figure, the S.P. log, which has been computed mathematically, is somewhat rounded at the level of each boundary, but its peaks are practically equal to those of the static S.P. diagram, whenever the thickness of the sand is more than twice the hole diameter. For smaller thicknesses, the maximum value given by the peaks is definitely reduced, and the S.P. log no longer reaches the static S.P. diagram. For sands having a thickness smaller than one-half of the diameter of the hole, the amplitude of the peak is approximately proportional to the thickness. With the assumption that all resistivities are equal, the proportionality factor is such that a thin bed, whose thickness is x pct of the drill-hole diameter, shows a deflection on the S.P. log which is about x pct of the maximum possible deflection, represented on the static S.P. diagram. This point is shown more clearly on Fig 7 and 8, discussed later.

Fig 4 represents an inverse case of the one illustrated on Fig 3, with shale beds of varying thicknesses, separated by thick salt-water sands. As can be seen, the log is simply the symmetrical image of the one represented on Fig 3. For thin shales, the deflection is approximately proportional to the thickness, with the same proportionality factor as for thin sands in thick shales.

Fig 5 is a composite log, illustrating the S.P. log in the case of various bed thicknesses. The bottom part of the figure is of particular interest, as it shows a succession of thin beds of sand and shale, hereafter referred to as a "sandwich." Comparing the S.P. log of the sandwich with the one of the homogeneous sand P_2, it can be seen that the sandwich is characterized by: (1) a smaller average deflection of the S.P. log; and (2) ripples about the average deflection.

When all resistivities are the same, as in the present case under discussion, the average deflection represents a percentage of the total emf, approximately equal to the percentage of sand in the sandwich. The ripple is a function of the thickness of the individual beds and decreases very quickly when the individual thickness falls below one-half the diameter of the hole. The discussion of thin interbedded layers in connection with the S.P. log is of particular importance when analyzing the problem of interpretation of shaly sands. This subject will be considered in more detail later on.

Influence of Resistivities of Formations and Mud

The effect of the resistivities of the media on the S.P. log is better considered as a function, not of their absolute values, but rather of the ratio between the resistivity of the formations R_t and the resistivity of the mud R_m. In the text, the value $\frac{R_t}{R_m}$ is called "resistivity ratio." Fig 6 illustrates the influence of the resistivity ratio on the S.P. log.

In order to permit an accurate computation, in each of the examples, the resistivity is chosen uniform for all beds, but now greater than the mud resistivity.

The S.P. log is similar in character to that where the formation resistivity is the same as the mud resistivity, except that: (1) the S.P. log is more rounded at the boundaries; and (2) the peaks in corresponding thin beds are reduced in amplitude.

These two effects are more pronounced as the resistivity ratio becomes greater. This is illustrated by Fig 6, which corresponds to the same formation arrangement as Fig 5, except where the resistivity ratio is 1, 6, 21, and 101. Fig 6 illustrates very clearly that, when the resistivity ratio increases, the S.P. log becomes more rounded, the peaks for thin beds are reduced in

amplitude, and, more generally, all details become less apparent; this is particularly noticeable in the progressive decrease of the ripples for the sandwich $P_{10}C_{11}$, and the amplitude of the S.P. log peaks in percentage of the static S.P. deflections. The abscissas represent the thickness of the permeable strata, in units of drill-hole diam-

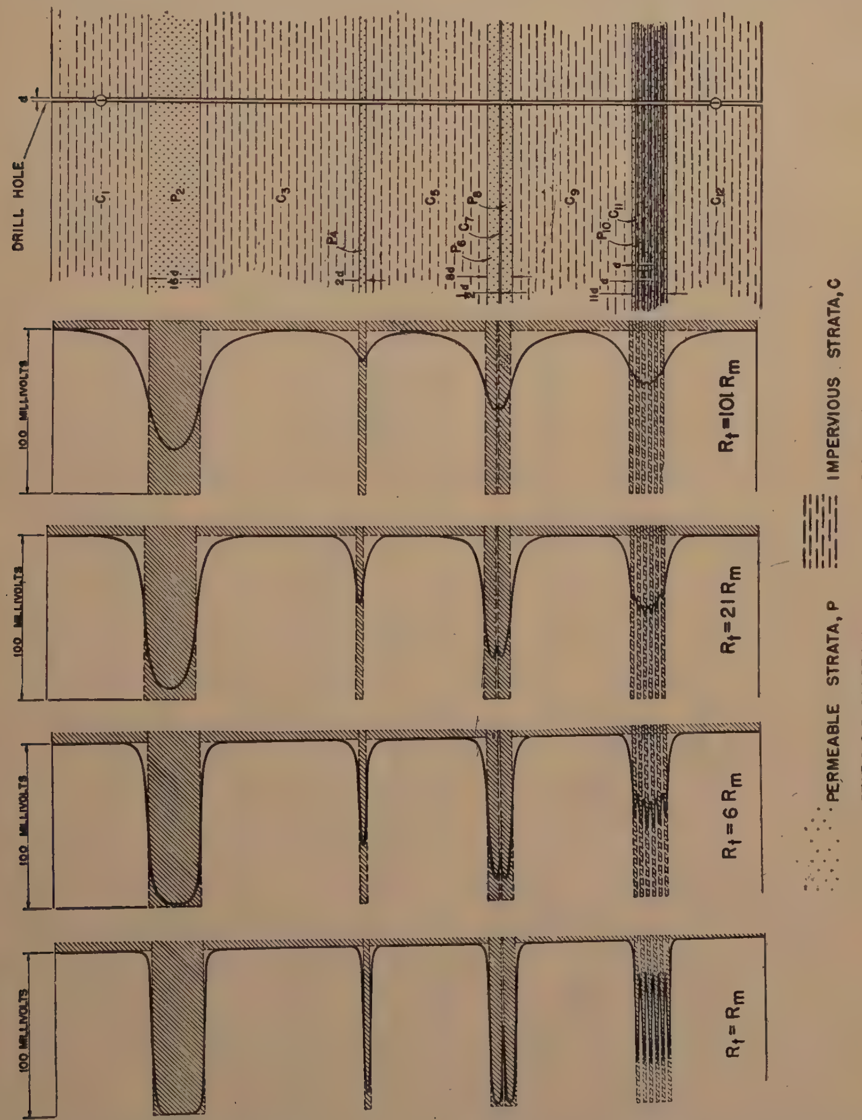


FIG 6—COMPARISON OF S.P. LOGS FOR DIFFERENT VALUES OF R_t/R_m.

almost imperceptible indication of the shale C_7 in the case $R_t = 101R_m$.

The effects of bed thickness and of resistivity ratio on the amplitude of S.P. log peaks are vividly illustrated on Fig 7 and 8. On Fig 7, the ordinates correspond to the eter. Several curves have been plotted, each corresponding to a different value of the resistivity ratio.

Fig 8 has the same ordinates as Fig 7, but the abscissas represent different values of the resistivity ratio. The chart consists

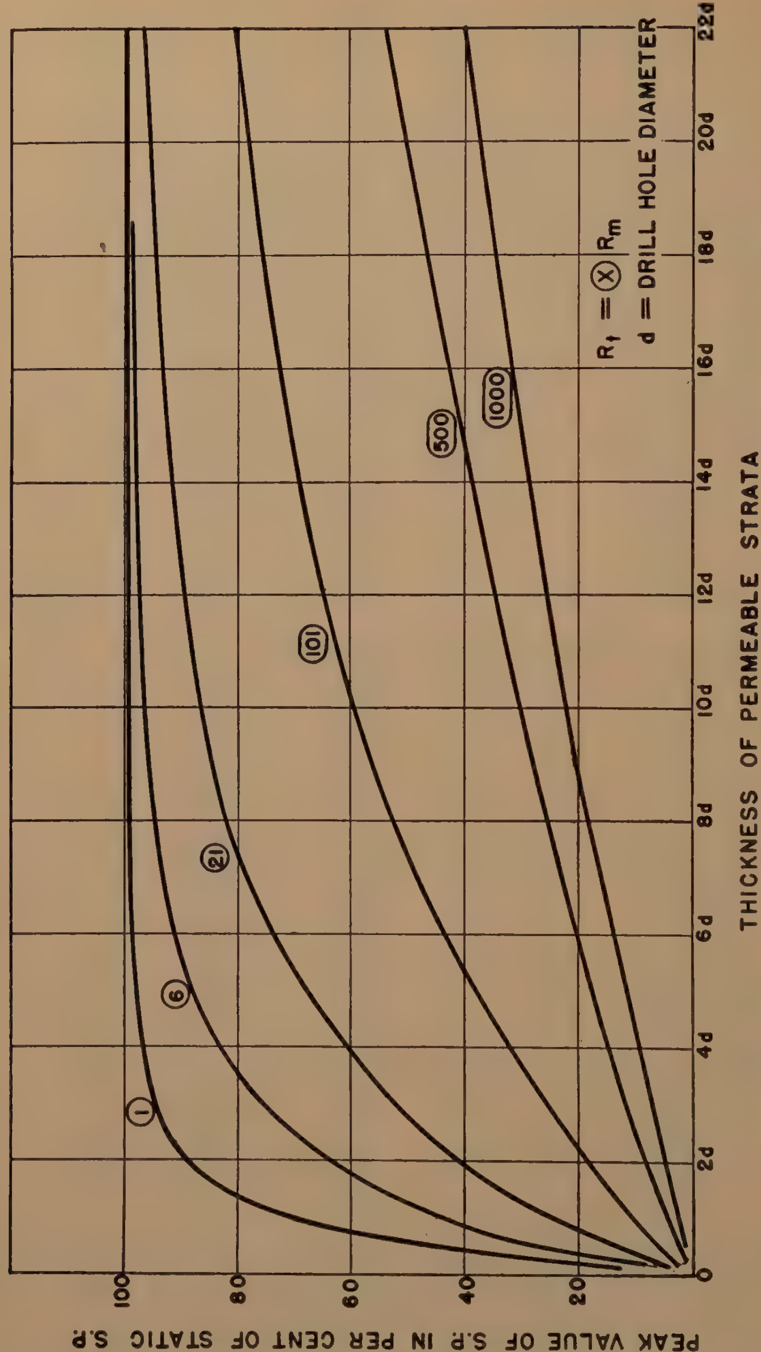


FIG 7—S.P. PEAK VALUE AS A FUNCTION OF PERMEABLE STRATUM THICKNESS FOR DIFFERENT R_t/R_m.

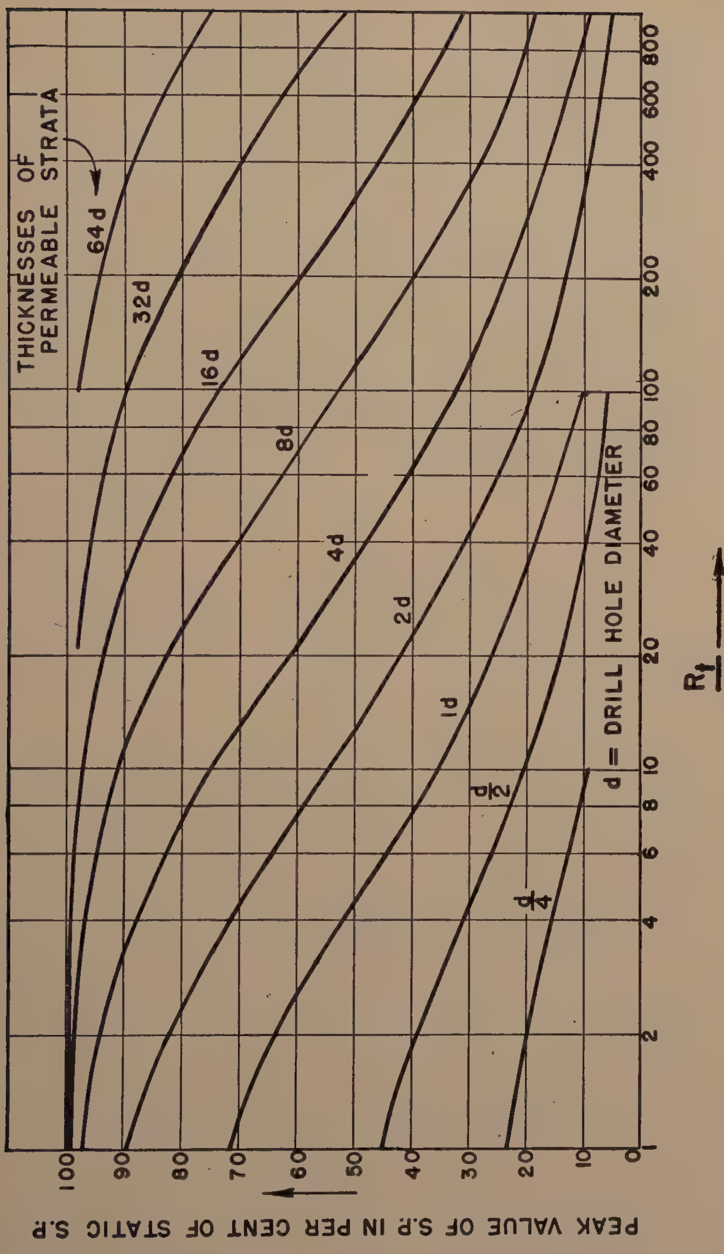


FIG 8—S.P. PEAK VALUE AS A FUNCTION OF R_t/R_m FOR DIFFERENT THICKNESSES OF PERMEABLE STRATA.

of several curves, each one corresponding to a given thickness of permeable strata measured in units of the drill-hole diameter.

It is apparent from these charts that over 90 pct of the maximum amplitude of the S.P. deflection at the center of a permeable stratum is reached for low resistivity ratios where the thickness of the stratum is over 6 times the diameter of the drill hole. Thus, thick permeable salt-water sands of low resistivity show S.P. values close to the static S.P. and the maxima on the S.P. logs do not vary appreciably for changes in thickness. For highly resistive media the S.P. deflection at the center of permeable strata tends to increase linearly with their thickness.

Remarks

In practice, the resistivities of the successive beds are not always the same; they may even differ widely, as when shales or salt-water sands are interbedded in compact sandstone or limestone. Then accurate mathematical computation of the S.P. log becomes very complicated and laborious.

Nevertheless, the preceding discussion is helpful in interpreting the S.P. log, as its shape remains generally the same. It should be noted particularly that, except in extreme cases, the boundaries between permeable and impervious beds still correspond to points of inflection on the log.

In the case of very thin beds, having a thickness of less than one-half of the diameter of the drill hole, the inflection points are slightly outside of the boundaries. This, however, does not appreciably affect the interpretation rule given in the previous paragraph, since the beds whose boundaries have to be determined in practice are generally of substantially larger thickness.

When the resistivities are different in a permeable bed and in the adjacent impervious stratum, the shape of the S.P. log will lack symmetry when it crosses the boundary. It will be more rounded in the more resistive formation than in the other one. Accordingly, the point of inflection will be displaced toward the top of the peak if the peak corresponds to the less resistive formation, and vice versa.

If both beds are thick, the point of inflection on the S.P. log may be determined with good approximation. The ratio of the number of millivolts between the base line of the impervious bed and the point of inflection, to the number of millivolts between that point and the maximum amplitude opposite the permeable bed, is approximately equal to the square root of the ratio of the resistivity of the impervious bed to the resistivity of the permeable bed.

Influence of Hole Diameter

An increase in hole diameter acts approximately like an increase in the resistivity ratio: it tends more to round the deflections on the S.P. log, and to reduce the amplitude of the peaks opposite thin beds.

Referring to previous figures, and particularly to Fig 7, it will be recalled that a decrease in bed thickness will affect the S.P. log. It should be kept in mind, however, that this effect is not a function of the absolute value of bed thickness, but rather of the ratio bed thickness to drill-hole diameter. Accordingly, an increase in hole diameter will decrease the ratio bed thickness-hole diameter. This will tend to decrease the amplitude of the peaks and to round the S.P. log near the boundaries.

Influence of Invasion by Mud Filtrate

In this section, it will be assumed at first that all the emf which generate the S.P. current at the level of permeable beds, are of electrochemical nature.

In this condition, penetration of mud filtrate into the permeable formation has an effect on the maximum of the S.P. deflection similar to an increase in the hole diameter. The equivalent hole diameter, however, becomes appreciably smaller than the diameter of the invaded zone, as the resistivity ratio increases.

In order to give an illustration of this effect, several conditions of invasion are shown schematically in Fig 9, where the resistivity ratio of the permeable stratum is assumed to be the same as the resistivity ratio of the adjacent formations. To allow exact computation, the invaded zone is considered completely invaded to a uniform distance, and the resistivity, R_i, of that zone is taken to be the same as the resistivity, R_t, of the undisturbed formation. The boundary between the invaded zone and the undisturbed formation is illustrated at P, Q, and R for diameter of invasion of $2d$, $4d$, and $8d$, respectively. The emf corresponding to the boundary between mud and permeable formation, which was at the wall of the drill hole, has now been displaced to the cylindrical surfaces shown at P, Q, or R.

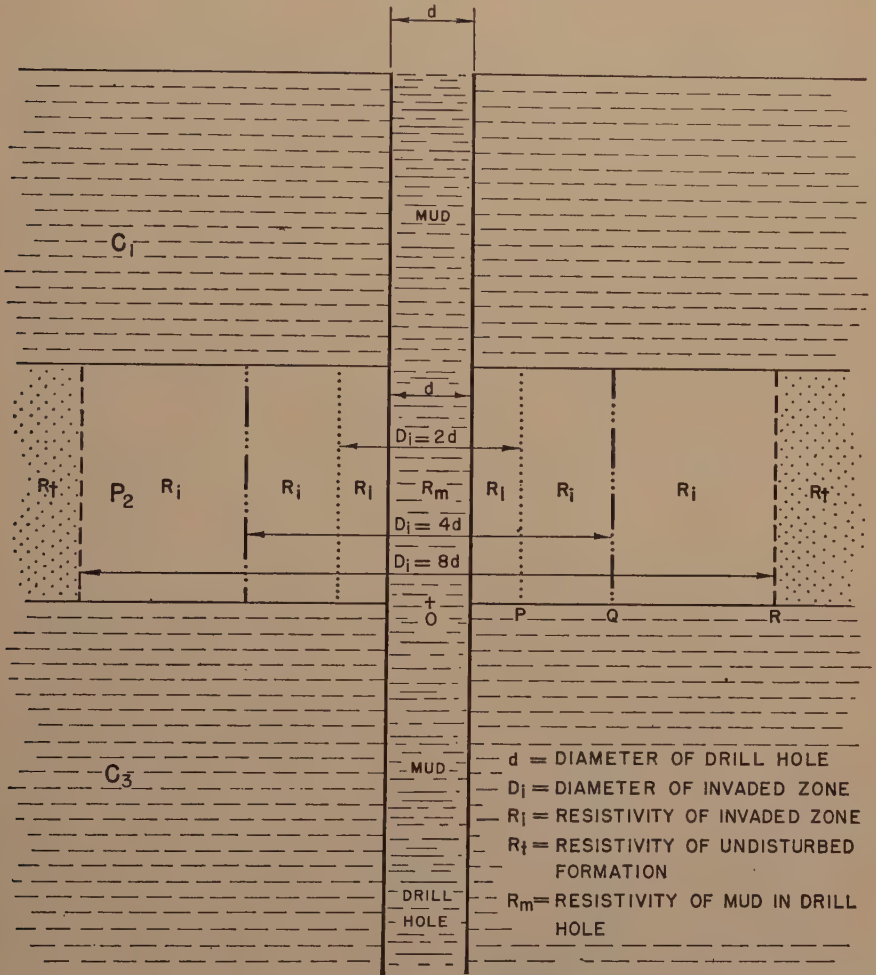


FIG 9—SCHEMATIC DIAGRAM FOR INVADED ZONES OF DIFFERENT DIAMETER WITH $R_i = R_t$.

The effect of invasion is shown by the S.P. log in Fig 10 for resistivity ratios 1, 6, 21, and 101, and for permeable beds with thicknesses d, $4d$, and $16d$. The maximum

deflection of the S.P. log for case of $R_t = R_m$ varies as if the hole diameter were simply increased to a diameter D_i in a case of no invasion. For a larger resistivity same absolute thickness without invasion, but with a hole diameter of $2d$. This also corresponds to a bed of thickness $2d$ in a hole of diameter d (see Fig 7).

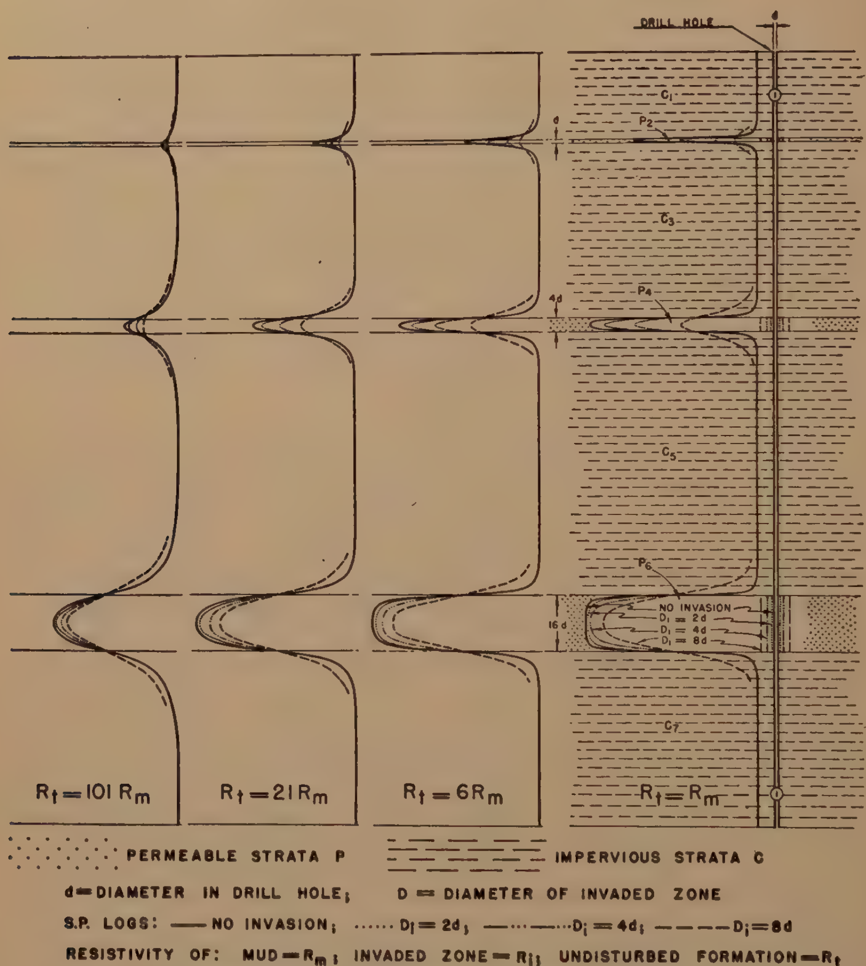


FIG 10—EFFECT OF INVASION ON S.P. LOG WITH $R_i = R_t$.

ratio, however, the maximum is affected as if the equivalent hole diameter were somewhat greater than the actual hole diameter, but appreciably less than the diameter of invasion. For example, where $R_t = 101R_m$, a permeable bed of thickness $4d$, invaded to a diameter of $8d$, gives a peak of approximately the same amplitude as a bed of

The shape of the S.P. log, though, is also affected by invasion. The dashed lines on Fig 10, illustrating the case for $D_i = 8d$, show that the S.P. peak is wider than for the case of no invasion.

The S.P. logs for the other two cases, for invasion to a distance of $2d$ and $4d$, whose excursions outside the permeable strata are

omitted from the figure, fall between the dashed line for maximum invasion of 8*d* and the full line for no invasion.

This spreading of the S.P. log beyond the boundaries of the permeable strata is similar to that caused by an increase in resistivity ratio, since the effective resistance within the cylinder determined by the invasion diameter, is less than the drill-hole resistance corresponding to the case where no invasion occurs.

The behavior of the S.P. peak for invasion in a given permeable stratum is qualitatively that to be expected for an increased effective hole diameter with no invasion.

Invasion not only reduces the amplitude of peaks corresponding to thin permeable beds, but it also has the same influence on the appearance of those inverse peaks corresponding to thin impervious beds located in invaded permeable formations (acting similarly, for example, to the case in Fig 4 for thin shale streaks in thick sands). This is another consequence of the correspondence which exists between the case of sands in shales, and the case of shales in sands.

It sometimes happens that a hole is first drilled with a given mud, so that the permeable beds are penetrated by the corresponding mud filtrate, and that afterwards the salinity of the mud is changed. This does not affect the analysis given, except insofar as the process of filtration may have created a zone of appreciably different resistivity in the permeable formations.

Such part of the S.P. potential differences in the mud, which is due to electrofiltration emf, is practically unaffected by invasion, except by resistivity change in the invaded zone, since the electrofiltration emf remains across the mud cake. For that reason, and when the electrofiltration emf is responsible for a substantial part of the S.P., the overall invasion effect is generally less pronounced than represented by Fig 10.

Special Topics

Certain selected topics of particular interest will be considered, based on an extension of the preceding discussion.

Interbedded Permeable and Impervious Layers—Sandwiches

The strata under consideration have thus far been bounded usually by comparatively thick beds. It is desirable, however, to examine the effect of interbedded layers of permeable and impervious strata. When there are thin layers of sand in shale, or thin layers of shale in sand, their combination constitutes what has been called a "sandwich," which can be considered as a more or less shaly sand.*

The effect of sandwiches has already been briefly mentioned in connection with Fig 5. It is further illustrated by Fig 11, 12, and 13 which are believed to be self-explanatory. These figures show the following points, with respect to the S.P. log:

1. On thick sandwiches the average deflection is approximately proportional to the percentage of permeable beds.

2. The average contour corresponding to a sandwich of finite thickness is the same for a homogeneous permeable bed of the same thickness and resistivity, but for which the total emf involved would apparently be smaller.

3. The amplitude of the ripples around the average curve decreases very quickly

* The expression "sandy shale" will not be used here, though the proportion of shale streaks is such that there is more shale than sand. Sandy shale will be considered as shale containing sand grains entirely encased in shaly material, the whole bed being completely impervious. From the point of view of the S.P. log, such sandy shales behave exactly like shales. On the contrary, beds containing sand and shaly material, including clay or other colloids, will be called shaly sands, whatever the proportion of shale, as long as they are permeable. In particular, sands that contain only a few per cent of shaly material, which would usually be considered as clean, will be placed in this paper in the category of "shaly sands." The term "clean sand" is reserved for sands containing no shaly or colloidal material. With that classification, most of the sands met in practice are shaly.

with decreasing thickness of the individual beds, so that the ripples are hardly noticeable when the individual thickness of both decreases when the resistivity of the permeable beds increases with respect to that of the impervious beds.

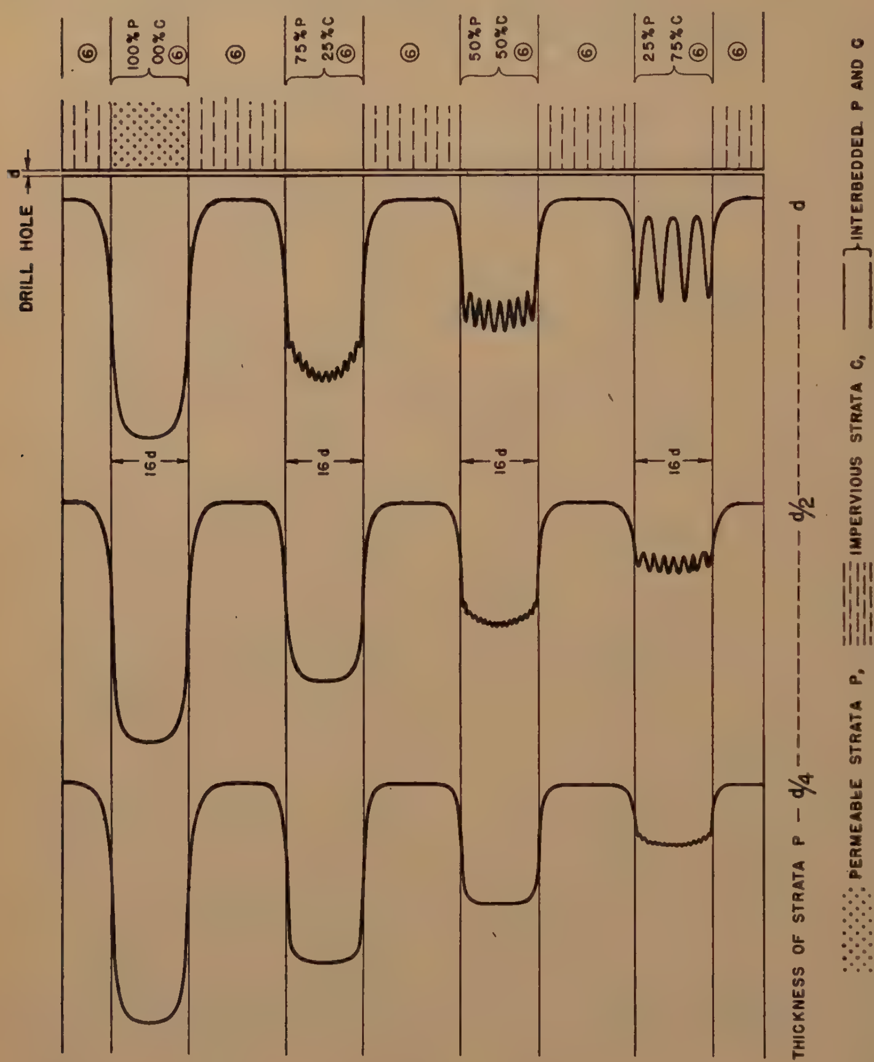


FIG 11—S.P. LOGS FOR UNIFORMLY THICK BEDS CONSISTING OF DIFFERENT PERCENTAGES OF INTERBEDDED PERMEABLE AND IMPERVIOUS STRATA VARYING IN THICKNESS ($R_i = 6 R_m$).

the impervious and permeable beds is less than one-half the diameter of the hole.

The following properties, which are not illustrated by the figures, must also be mentioned:

1. The amplitude of the ripples decreases when the permeable beds are invaded by the mud filtrate.

2. The average amplitude of the peaks

This latter phenomenon is of particular interest, when a certain section of a shaly sand is oil bearing, while another section is water bearing.

Shaly Sands

The expression shaly sand has been applied above, in a general way, to interbedded thin streaks of sand and shales, or,

in other words, to stratified compounds of sand and shale. There are, however, sand beds with certain unstratified shaly material, and which must, therefore, also come under the category of shaly sands.

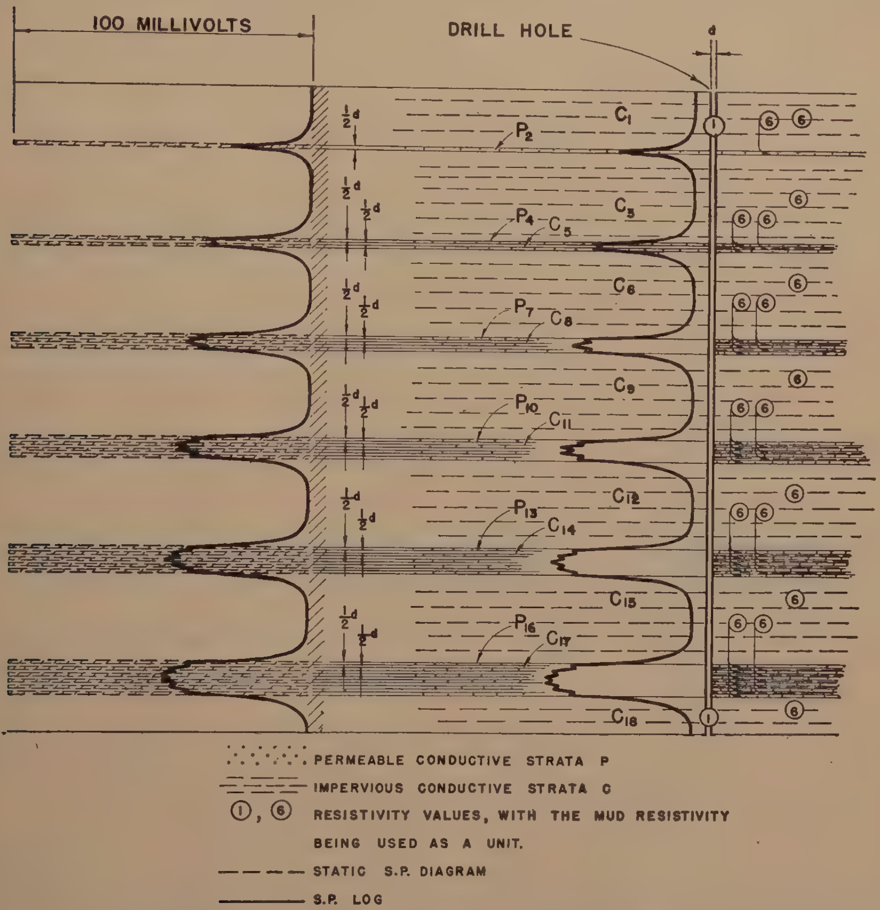


FIG 12—S.P. LOGS FOR INCREASING LAYERS OF THIN INTERBEDDED PERMEABLE AND IMPERVIOUS STRATA ($R_t = 6\ R_m$).

Whether the different shaly particles enclosed in a shaly sand are stratified or not, the compound behaves substantially in the same way from the point of view of the S.P. log, provided that the shaly sand remains permeable. In unstratified shaly sands, the shale particles* which are entirely surrounded by mud filtrate, or by the original interstitial water, generate no S.P. currents, because there is no chain emf. When, however, a shale particle is in contact on one side with the mud filtrate, and on the other side with the original interstitial water, the 3 media constitute a 3-link chain and generate S.P. currents. The total of the S.P. currents generated around each particle add their effects, and the corresponding S.P. log is identical to the one that would have been obtained if the same amount of shale contact had been present in the form of thin interbedded shale streaks.

* The word particle is to be interpreted as meaning an agglomeration of minute solid parts together with their adsorbed water.

In other words, the amplitude of the S.P. log does not depend on the type of repartition of the shaly material in a permeable shaly sand, provided, of course, that the average repartition is uniform. The amplitude, however, is maximum for a clean sand and it is reduced with increasing percentage of shaly material.

If there is a progressive change in the nature of the fluid, going from mud filtrate to interstitial water, in the zone of the unstratified shaly sand invaded by the mud filtrate, the result is still the same as for a stratified shaly sand. In that case, there are, of course, no shale particles simultaneously in contact with the mud filtrate and with the original interstitial water, but there are a large number of shale particles, parts of whose surfaces are in contact with water of varying salinities. Each such particle generates a small emf, but, because there are many more particles involved, the effect of the total S.P. current generated by all of them is the same, and the action on the S.P. log is unchanged.

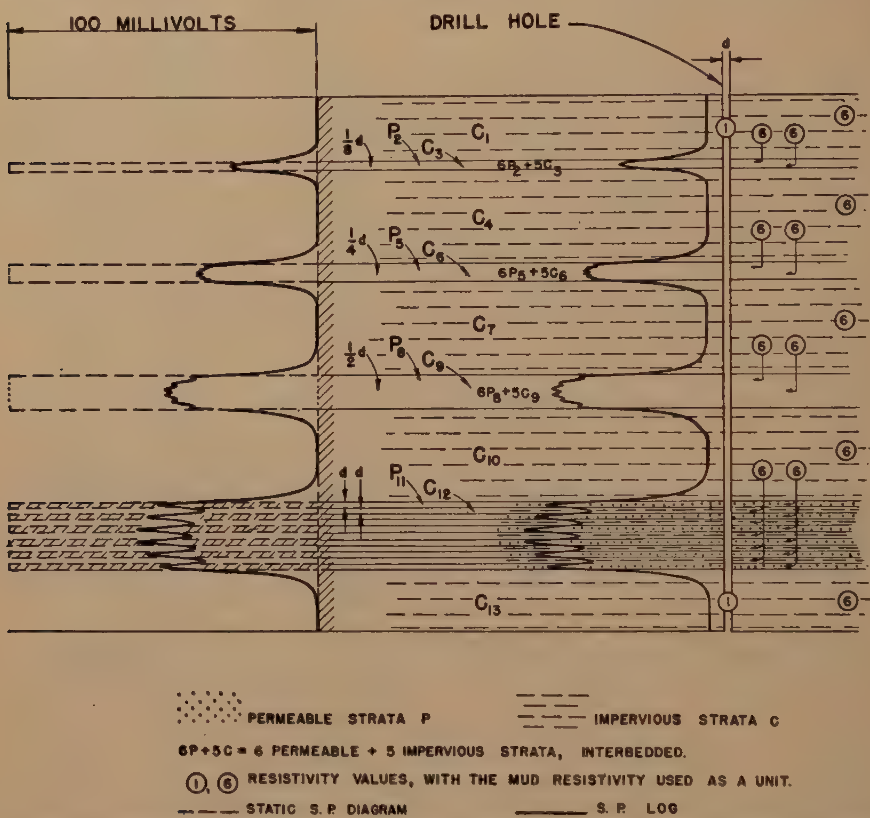


FIG 13—S.P. LOGS FOR DIFFERENT THICKNESSES OF INTERBEDDED STRATA FIXED IN NUMBER ($R_t = 6\ R_m$).

The result is that all the conclusions given above in connection with the stratified shaly sands remain valid in the case of unstratified shaly sands.

Pseudo-static S.P. for Shaly Sands

When the sand and shale streaks in a shaly sand are very thin, it is almost impossible to represent the detailed variations

of the static S.P. diagram at the scale normally used, that is 5 in. per 100 ft. On the other hand, the S.P. log for a shaly sand, in which the average proportion of shaly material is the same at all levels, is identical to the S.P. log for a clean sand giving an apparently lower emf (as if it were, for example, a clean sand of lower salinity), and may be represented by a uniformly reduced static S.P.

This lower emf, which would give the same S.P. log in the case of a clean sand, will be called hereafter the "pseudo-static S.P." In fact it is the S.P. that would be measured in front of the shaly sand if insulating plugs were set at its upper and lower boundaries, as in Fig *2a*, to interrupt the mud continuity at these levels. The pseudo-static S.P. represents the maximum possible average deflection for such shaly sand, which is reached only if the shaly sand is thick enough.

Shaly Sands Containing Oil

The presence of oil in a shaly sand will increase the resistance of the permeable part of the medium. It can be shown that this increase will lower the pseudo-static S.P. Accordingly, the amplitude of the deflection on the S.P. log can be expected to be smaller opposite an oil-bearing section than opposite a water-bearing section. Such a change in the deflections of the log can only be found for shaly sands or for thin sands; it will not occur for thick clean sands.

As many sands are shaly, it is not surprising that a change in the S.P. log deflection has been found when passing the oil-water contact in a sand. It is to be noted, however, that the change in the S.P. log deflection is not a positive diagnostic for the detection of oil, since the same effect would be obtained if the salinity of the interstitial water were reduced, or if the percentage of shale were increased. If there are good reasons to believe that the salinity of the water remains substantially constant in the interval being studied, and that the shale content within the sand is approximately the same, then the level at which the S.P. deflection is less is a good indication of oil content. Such a possibility is at least to be considered, if concurrently the resistivity is higher, indicating that an increase in shale percentage is not the probable explanation for the lower deflection.

The presence of gas in shaly sands may affect the S.P. log in the same manner as the presence of oil. It seems, however, that there is a tendency for such shaly sands to show a little less S.P., and a slightly higher resistivity when they contain gas than when they contain oil. This may be due to less connate water being left in the reservoir in the case of gas.

Transition Zone

Between a substantially clean sand and a shale, there may be a transition zone of more or less shaly sand. In such a case the pseudo-static S.P. for the shaly sand part is intermediate between the respective static S.P. for the shale and for the sand, as represented on Fig *14c*.

If the transition zone is not very thick, or if, as has been assumed on Fig *14c*, the resistivity of the formation is much higher than that of the mud, the S.P. log is too rounded to show a plateau at the level of the transition zone. Instead, there simply is an inflection point, corresponding to a minimum slope, at the level where the actual S.P. potential in the mud is equal to the pseudo-static S.P. In addition there are, of course, inflection points corresponding to maximum slopes, at the boundaries of the transition zone.

This particular case is brought up here to show that, in special cases, there could be inflection points which do not characterize a boundary between an impervious and a permeable bed. It is important to note, however, that the special inflection point mentioned here corresponds to a minimum slope, while inflection points at boundaries

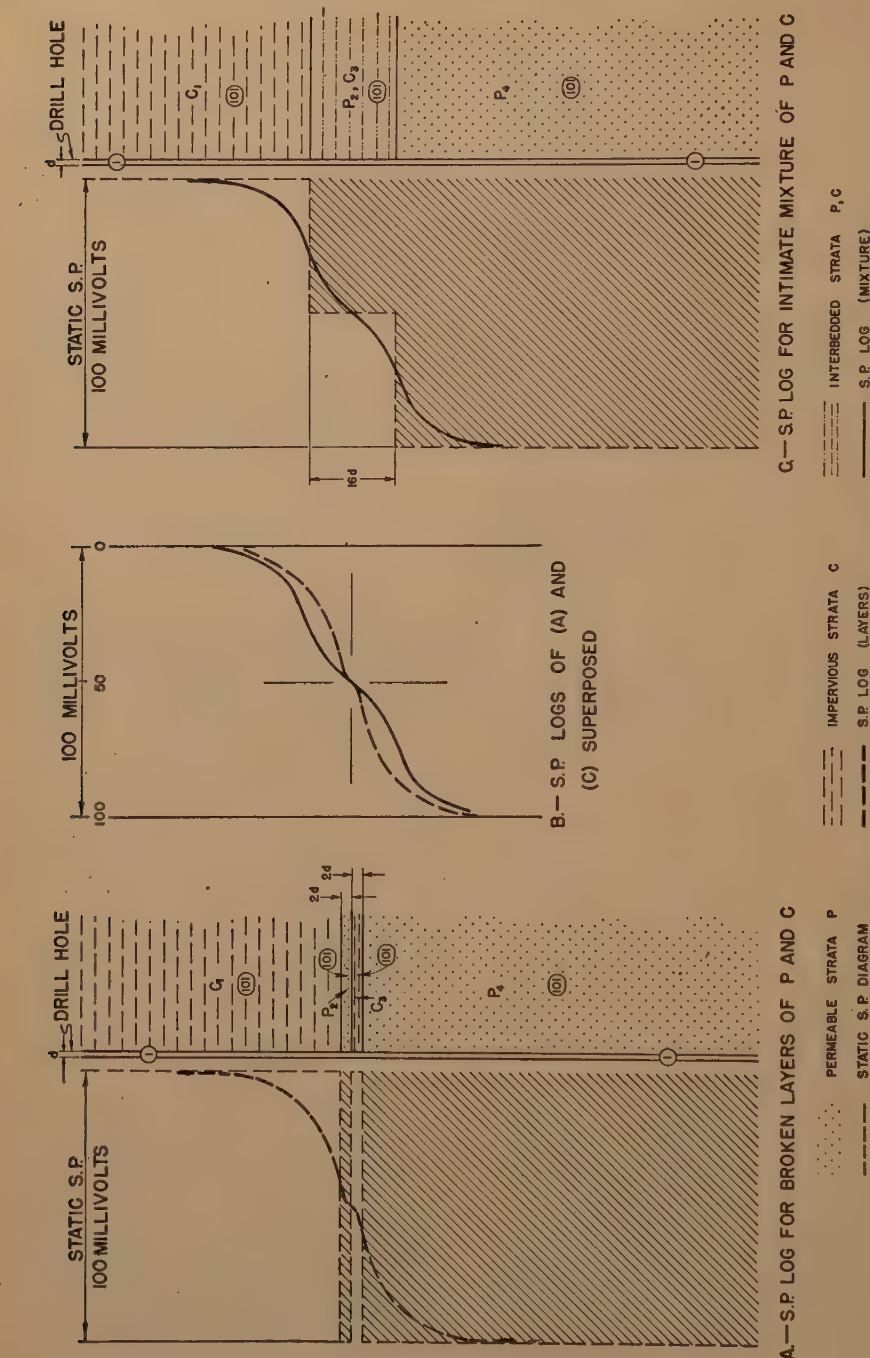


FIG 14—SHAPE OF S.P. LOGS FOR DIFFERENT TRANSITION ZONES AT BOUNDARY OF PERMEABLE BED.

correspond, in practically all cases, to maximum slopes.

Fig 14*a* shows a particular case, on the other hand, where the transition zone is made of two thin beds, one permeable and the other impervious, whose contact, or boundary, is characterized on the S.P. log by an inflection point corresponding, though, to a minimum slope. The purpose of this figure is to show that, in certain special cases, there could be an inflection point coinciding with a minimum slope, and which nevertheless characterizes a boundary. In such a case, however, there would generally be sharper curvatures on both sides of the inflection point, as is illustrated by Fig 14*b*, when the logs of Fig 14*a* and 14*c* are superposed.

There might be cases where, in the transition zones, the percentage of shale content increases continuously toward the shale. In such instances the pseudo-static S.P. itself would vary continuously from the sand to the shale. The S.P. log would show an almost constant slope, with no definite inflection points, and this would be in accordance with the fact that there is no definite boundary in the formations themselves.

Area under the S.P. Log

The expression "area under the S.P. log," for a given interval, designates the area between the S.P. log and its base line, for that interval. It will be assumed in this section that the permeable formations are sands and the impervious formations are shales; the shale line, which corresponds to the S.P. in front of thick shales, is taken as the base line. In that case, the area under the S.P. log is the area between the log and the shale line (or its continuation) for the given interval.

The reason for considering this area is that, under favorable circumstances, and in particular when the resistivities of sands and shales are approximately equal, it gives a useful indication of the respective proportions of sands and shales. When, in a given interval, there are only thick sands and thick shales, the boundaries between them are easily determined and correspond to the inflection points on the S.P. log, which shows quite sharp deflections in that case. When, however, some of the successive sands and shales are rather thin, the S.P. log shows ripples which are difficult to distinguish, and it is practically impossible to determine the boundaries of each individual sand bed. In such a case the area under the S.P. log may be of great help, if used with care.

In the ideal case, where the sands and shales have the same resistivity, and even though that resistivity is quite different from that of the mud, the area under the S.P. log is the same as the area under the static S.P. diagram. For a given geological horizon the shale line is usually approximately straight, and it can generally be assumed that the static S.P. is the same for all sands. Furthermore, the value of the total emf, or static S.P. difference between shales and sands, can generally be determined from the log. This will be done in a region of thick sands that can be considered reasonably clean, containing the same interstitial water as the other sands, and having approximately the same differential pressure.

Having determined the static S.P., it is an easy matter to evaluate the sand thickness in interbedded sections of sands and shales belonging to the same general horizon. The sand thickness will be obtained from the following relation:

$$\text{total thickness of sand} = \frac{\text{area under the S.P. log}}{\text{total emf}}$$

in which both quantities in the second member are derived from the S.P. log.

Consistent units must be used for the area, for the total emf, and for the total thickness. If, for example, the total area is

expressed in ft-mv, the total emf must be measured on the S.P. log in millivolts; the total thickness is then expressed in feet.

When the resistivity of the sands is not equal to that of the shales, the quantitative rule given above becomes less precise. In that case, however, it is still useful, because it gives a rough approximation of the proportion of sands. This approximation constitutes a lower limit to the equivalent thickness of the sands, when the sands are more resistive than the shales. Similarly it constitutes an upper limit, when the shales are more resistive than the sands.

If the method is applied to unstratified shaly sands, it will give an equivalent sand thickness which is less than the actual distance between boundaries, but this is probably a better estimate. Since both the porosity and permeability of such shaly sands are generally less than that of clean sands, they behave like reservoirs of reduced thickness. The estimate of equivalent sand thickness tends to correspond to the reduced reservoir.

In the case of intervals which are primarily made of sands, with a smaller proportion of shale streaks, the same reasoning can be applied to the determination of the total thickness of shale in any given interval. In that case, it is more practical to measure the area between the S.P. log and a base line determined by the maximum deflections opposite the sands. As in the other case, the rule is quantitative if the resistivities are equal. Otherwise, it gives only an approximation, which is an upper limit for the proportion of shales if they are less resistive than the sands.

The rule concerning the area under the S.P. log is not affected by a change in the diameter of the hole. Invasion of the permeable beds by the mud filtrate does not affect it either, except for the influence of a change in the resistivity of the invaded zone.

An examination of the examples of S.P. logs, illustrated in previous figures, particularly Fig 6 and 11, shows the applicability of the rule for various cases.

For an evaluation of reservoirs, the discussion on the area under the S.P. log gives a new approach to an important problem. A word of caution should be given: the established rule can only be applied with assurance when the resistivities of the permeable bed and adjacent beds are very nearly the same. When these resistivities differ, the area under the S.P. log is modified to an extent difficult to evaluate mathematically.

Base Line Shifts

It has been assumed throughout the paper that the S.P. was the same in front of all thick shale beds, or, in other words, that there was a straight "shale line" or "base line" on the S.P. log. Field experience shows, however, that, in certain fields, there is a systematic shift of this shale line which occurs always at the same location in the geological column. In fact, in certain cases, such base line shifts constitute excellent markers.

The shift is generally caused by a difference in the nature of the shales above and below the shift level. There can, however, be a shift in the base line, even though the shales above and below the shift level are of the same nature. This occurs when there is, in the ground, a dissymetrical sequence of formations constituting one or more 3-link chain emf which do not cancel out.

S.P. Log in Limestone Fields

The case of limestone fields, and more generally of permeable beds in compact and highly resistive formations, deserves a special study.

The permeable zones, whether oil bearing or water bearing, are somewhat conductive because of the capillary water of generally high salinity which is present in the pores. The other conductive beds, like shales for example, are of impervious nature. When

the permeable and impervious beds are thick and sufficiently conductive, the S.P. log approaches the static S.P. diagram, so that the number of millivolts recorded in front of a permeable zone differs from the one recorded in front of an impervious bed by an amount approximately equal to the emf involved, as in the general case.

When, however, the conductive beds are not very thick, and are separated by thick hard formations of high resistivity, the S.P. log has a shape which is difficult to understand at first glance. This comes from the fact that the very resistive formations tend to prevent the S.P. currents from leaving or entering the hole opposite their level. The S.P. currents thus have to flow into the hole almost entirely by way of the permeable beds and of the nearest conductive impervious beds. In so doing, the S.P. currents produce potential differences by ohmic effect in the mud in front of the hard re-

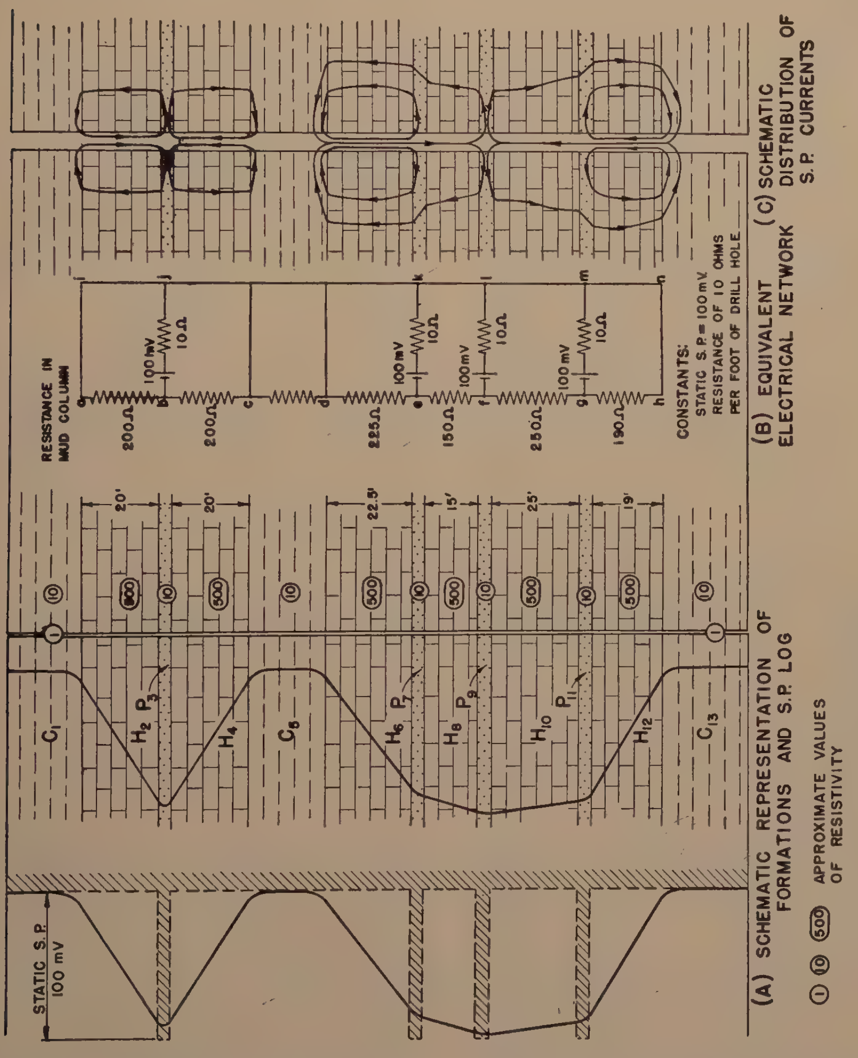


FIG 15—SCHEMATIC REPRESENTATION OF S.P. PHENOMENA IN HIGHLY RESISTIVE FORMATION.

sistive formation. The result is that the peaks corresponding to the permeable zones spread above and below these zones in an apparently abnormal manner.

It will be shown here, with the help of a theoretical example, that the curious behavior of the S.P. log is more easily explained, and that the interpretation becomes less difficult, once the principles have been established.

Fig 15*a* represents, in a schematical way, the case of 4 thin permeable zones P_3, P_7, P_9, and P_{11}, and 3 thick shales C_1, C_5, and C_{13}, separated from each other by thick, compact, and highly resistive beds H_2, H_4, H_6, H_8, H_{10}, and H_{12}. In order to characterize the problem more explicitly, it is assumed, with the resistivity of the mud being taken as a unit, that the resistivity of the permeable zones, as well as that of the shales, is approximately 10, while the hard formations have a resistivity of 500 or more.

The S.P. log that corresponds approximately to such a case is given in Fig 15*a*. The segments of that log which correspond to hard formations are represented by straight lines (more precisely, they should have slight curvatures as will be explained later, but the log would be similar in appearance).

The emf involved are, as usual, represented by the static S.P. diagram on which the S.P. is superimposed. As can be seen, the departure of the S.P. log from the static S.P. diagram is remarkable in this case, and there is no wonder that this type of log has sometimes been considered abnormal. In Fig 15 it is assumed that the static S.P. in front of the hard formations is the same as that in front of the shales. In this schematical example, any other reasonable value could have been assumed for the static S.P. in front of the hard formations* without changing appreciably the corresponding S.P. log. This is because the hard formations, as represented, are much too resistive to allow any appreciable S.P. current to diverge into the mud, and thereby to influence the potential. What happens under other conditions will be discussed at the end of this section.

The shape of the S.P. log is easily understood if the circulation of the S.P. currents is studied first. This circulation is represented, in a quite schematical way, on Fig 15*c*. The S.P. currents, which are generated by the different emf, flow into the sands.

They cannot traverse the adjacent hard formations through sections located close to the drill hole, because these sections are too small in area and, therefore, introduce into the circuit large resistances which would practically prevent the current from flowing. On the contrary, the S.P. current penetrates deeper than usual in the permeable beds and, consequently, enters the hard formations through larger cross sections. From there on, it is easier for the S.P. currents to continue their path in the hard formations without appreciable reduction in their cross section, as would be required if they were to converge quickly toward the hole. The S.P. currents flow therefore toward conductive beds through which they can return to the mud in the hole, and then, through the mud, back to the permeable beds to close their circuits. They cannot come back to the mud through other permeable beds, because they would encounter emf which would oppose the flow of currents in that direction. When the first conductive beds they encounter are of the permeable type, they simply cross them until they reach conductive and impervious beds. This is the case for the S.P. currents which penetrate the permeable bed P_9; they have to cross the permeable bed P_7 in order to reach the impervious bed C_5, or have to cross the permeable bed P_{11} in order to reach the impervious bed C_{13}.

* Needless to say, hard formations met in practice are not quite as sharply defined and differentiated as those represented on the figures.

The total potential drop along a current path is equal to the total emf involved. The currents divide between the different possible paths and produce in them potential differences, according to Kirchhoff's laws. As it is difficult to visualize the application of Kirchhoff's laws to the 3-dimensional circuit constituted by the formations and the mud column, the problem can be clarified by referring to the equivalent electrical network of Fig 15*b*.*

In that network each permeable bed is characterized by an emf—the total emf which generates the S.P. currents—and by a resistance which is the one the S.P. currents encounter in that permeable bed and in the surrounding hard formations, before the current path has expanded to very large cross sections at great distances from the hole (which great distance will be referred to as infinity). The permeable bed P_9, for example, is represented by an emf of 100 mv in series with a resistance of 10 ohms. These 10 ohms represent approximately, for the resistivities indicated on Fig 15*a*, the resistance between the cylinder of mud in contact with bed P_9 and infinity. The ground at large distance from the hole is represented on the schematical circuit by the conductor *ijklmn*, which is supposed to have no resistance.

The conductive and impervious beds C_1, C_5, and C_{13} are represented on Fig 15*b* by short circuits between the mud and infinity, as these beds are so thick that they oppose very little resistance to the current. No emf is shown between the mud and infinity in the impervious beds, because the total emf has been assumed to be at the boundary between the mud and the permeable beds. This total emf could, however, just as well have been divided between the permeable and the impervious beds, and this would not have changed the currents nor the potential difference across the resistances representing the mud column.

The mud column is represented by resistances which have a constant value per foot of hole, and have been computed on the basis of a hole diameter of 8 in. and a mud resistivity of 1 ohm meter.

When the bed resistances are small with respect to the resistances of the mud sections, practically all the potential drop is produced in the mud, and the total deflection of the S.P. log is nearly equal to the total emf involved. This is illustrated in the figure, for bed P_3 for instance, where the resistance in the formations is 10 ohms as compared to 200 ohms for the resistance in each mud section. When, however, the bed resistances represent a large part of the total resistance, the deflections of the S.P. log do not reach the maximum corresponding to the total emf.

All along a drill hole opposite a given hard formation, the current in the mud column remains substantially the same, and so does the drop of potential per unit length of hole, thus giving a constant slope as shown by the S.P. log.

At the level of each conductive bed, some S.P. current generally penetrates or leaves the hole, therefore the slope of the S.P. log is modified. On Fig 15*a*, for example, the S.P. log changes its slope at the level of the permeable bed P_7, because part of the current leaves the hole and flows into that bed. In the particular case of bed P_7, the S.P. current in the drill hole flows in the same direction above and below it, and the slope is simply changed but not reversed. The situation is different in the case of the permeable beds P_3 and P_9: at their levels, the direction of the current in the hole is reversed, and so is the slope of the S.P. log.

When there is only one permeable bed like P_3 between two successive impervious beds like C_1 and C_5, that permeable bed is

* It may be interesting to mention that the circuit shown has actually been built and used to determine the schematical log represented on Fig 15*a*. The potentials at points *b c—h* have been measured with respect to the potential of *a* with a high resistance millivoltmeter, and the S.P. log interpolated between the characteristic points thus determined.

easy to detect on the S.P. log, even when hard formations like H_2 and H_4 are present, because a very definite slope reversal occurs opposite the permeable bed. In the case of such an isolated permeable bed, a remaining difficulty is to determine exactly its boundaries.

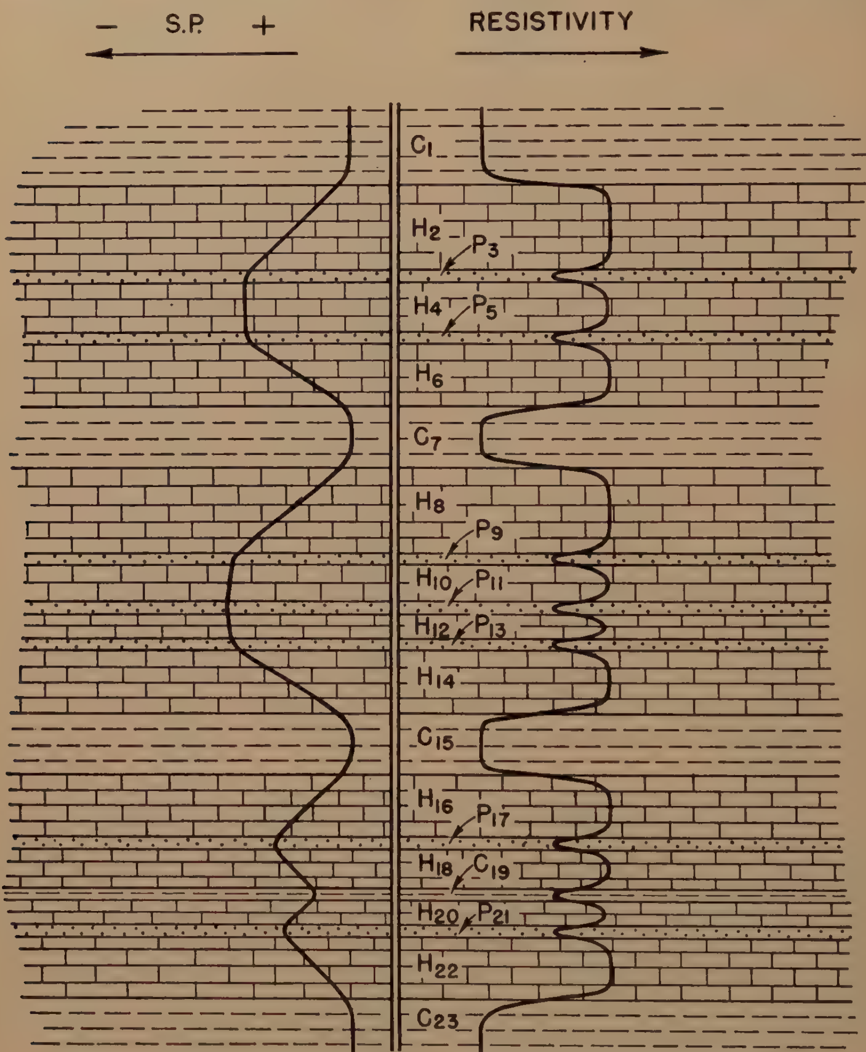
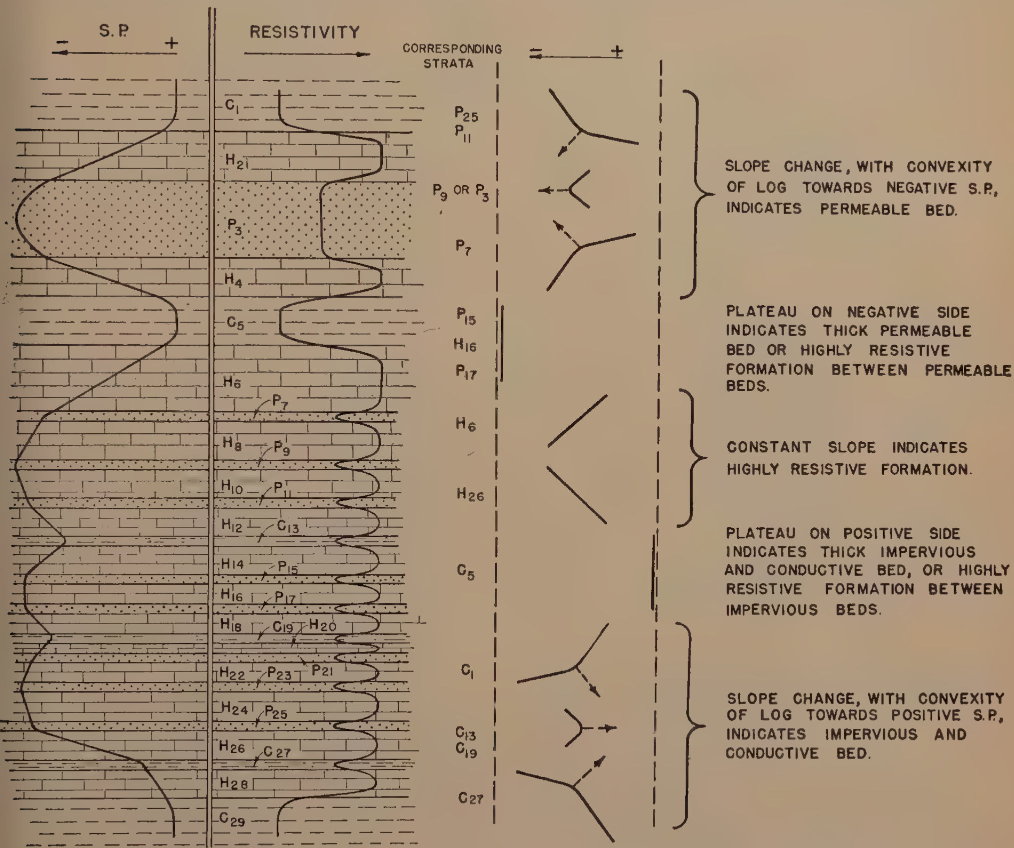


FIG 16—SCHEMATIC EXAMPLE OF S.P. LOG IN HIGHLY RESISTIVE FORMATIONS.

The interpretation is less evident when there is a succession of permeable beds separated by hard formations, as in the case of beds P_7, P_9, and P_{11}. Miscellaneous examples corresponding to that case are shown by Fig 16 and 17, on which the corresponding S.P. logs and resistivity logs* have been represented schematically to illustrate the principles of interpretation.

* The resistivity logs which are represented schematically on Figs 16 and 17 correspond to a so-called "limestone device," or symmetrical sonde. This type of electrode combination is particularly useful when the problem

The large negative peaks from P_3 to P_5 and from P_9 to P_{13} on Fig 16 are very similar, and do not show clearly what there is in each interval. However, the resistivity tion, as to what the conductive beds are, is resolved by the S.P. log, which shows without any doubt that bed C_{19} is impervious, while beds P_{17} and P_{21} are permeable.



A.—SCHEMATIC ELECTRIC LOG. B.—ANALYSIS OF CHARACTERISTIC SHAPES OF S.P. LOG.

FIG 17—INTERPRETATION OF S.P. LOGS.

log gives additional information which makes the interpretation easy. Conversely, it can be observed that the resistivity log corresponding to beds P_9, P_{11}, and P_{13} is very similar to that corresponding to beds P_{17}, C_{19}, and P_{21}. But here the indetermina-

consists primarily in locating the conductive zones in hard formations. One of the peculiarities of this device is to tend to give a constant value when the resistivity of the formation becomes much higher than that of the mud. This explains why the log approaches a constant limit in front of all hard formations. The principles given here, however, also apply to electrical logs recorded with the standard electrode arrangements.

The characteristic shapes of the S.P. log which make it possible to determine the nature of beds, are summarized on Fig 17, which is self-explanatory.

In most of the schematic examples the permeable beds considered were rather thin. Nevertheless for thick beds the reasoning remains valid as illustrated for bed P_3 of Fig 17.

Besides the zones which are definitely porous and permeable, and might therefore be of commercial interest if they contain oil, hard formations, like limestones, may

also comprise zones which would be classified as compact, because their porosity and permeability are too small to be of any practical value. These formations designated as compact may, however, behave like the more permeable zones, from the standpoint of the boundary emf. When the permeability becomes smaller and smaller, the static S.P. remains probably unaffected down to permeabilities of only a small fraction of a millidarcy. Concurrently, though, the resistivity becomes so high that the ability of the strata to conduct current from, or into, the mud becomes progressively less as the permeability decreases. This means that the drop of potential in the mud of the drill hole, caused by the current flow produced by the static S.P. in this type of formations, becomes negligible.

For zones of extremely low porosity and permeability, it is probable that the static S.P. is smaller than for highly permeable strata, although likely higher than for shale beds. This, however, is difficult to prove, precisely for the reasons that these zones have too high a resistivity to clearly influence the S.P. log. Qualitative indications concerning the corresponding static S.P. can, nevertheless, be obtained in favorable cases. For example, if such a substantially thick zone of extremely low permeability is between two shales, it tends to show on the S.P. log by a small and rounded excursion toward the negative, which indicates that its static S.P. is more negative than that of the shales.

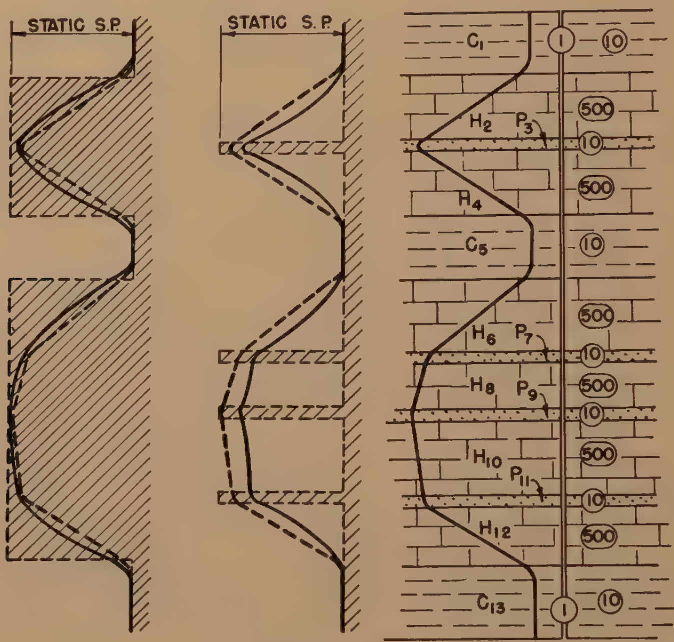


FIG 18—SCHEMATIC REPRESENTATION OF S.P. LOGS SHOWING THE EFFECT OF SLIGHT CONDUCTIVITY IN HARD FORMATIONS FOR DIFFERENT STATIC S.P.

As long as the formations are somewhat conductive, current passes from the mud into the formations at all levels where the static S.P. is more negative than the actual S.P. in the mud. The current loss per foot of hole is proportional to the difference between the static S.P. and the actual S.P.,

and also to the conductivity of the formations. This results in a progressive change in the slope of the S.P. log, or, in other words, in a slight bending of the curve with convexity toward the negative. Inversely, wherever the static S.P. is more positive than the actual S.P. in the mud, the current flows from the formations into the mud, and the convexity is toward the positive side of the curve.

To illustrate the above remark, the schematical example of Fig 15 has been represented again on Fig 18, with the assumption that the hard formations H_2, H_4, H_6, H_8, H_{10}, and H_{12}, have enough conductivity to influence the S.P. log.

Fig 18*c* refers to the case where their static S.P. is more negative than the actual S.P. logged in the mud, while Fig 18*b* shows the reversed case. The polarity of the difference between the static S.P. and the actual S.P. in the mud was reversed in Fig 18*c* with respect to Fig 18*b*, in choosing a different value for the static S.P. opposite the hard impervious formations, as shown on the figure.

Examples

In this section, field examples are given illustrating some features of the preceding discussion.

Application of the S.P. Computations to a Field Example

The example shown in Fig 19 comprises several interesting features. It illustrates that base lines are relative, that impervious media act as the inverse of permeable media for their effect on the S.P. log, and that the mathematical computations have a wider range of practical application than would appear from their postulates (such as the assumption of uniform resistivity ratios).

A long section of an electrical log through a shale and a lime section is shown in Fig 19*d*. It is evident that where the shale is predominant, in the upper section and at the very bottom of the log, the base line is toward the positive S.P. In the lime section, known as such from other data, the S.P. log stays on another base line, displaced a uniform amount toward the negative S.P., for an interval of over a thousand feet. Thus, permeable beds in the upper section are indicated by excursions to the left of the base line, while impervious beds in the lime section are indicated by excursions to the right of another base line.

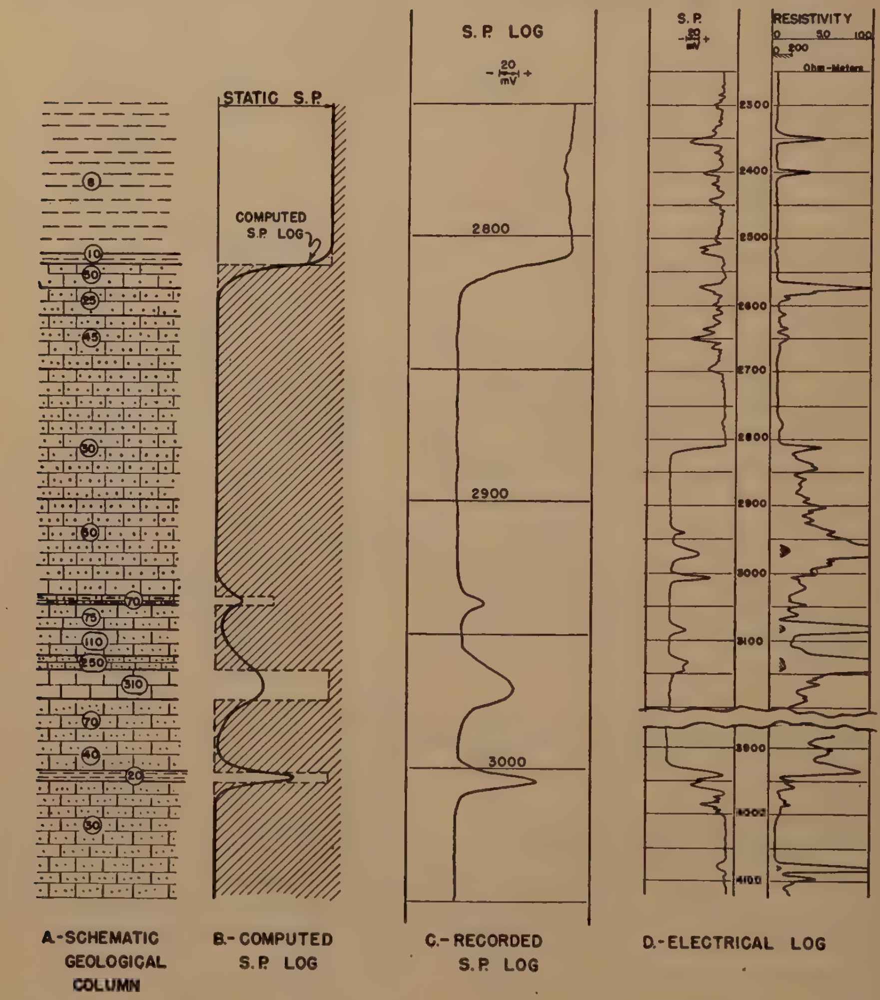
These relationships show that the base line is an arbitrary choice. Thus, since the shales are conductive and generally more abundant, they provide, in most cases, a good choice for a base line. When, however, as in the present example, there is a long interval consisting of a permeable bed with only a few impervious sections, the permeable bed line, which constitutes a negative limit of the S.P. log, may give a more practical base line within that interval. This is one more illustration of the symmetrical nature of the S.P. log.

An enlarged section of the S.P. log is shown in Fig 19*c*. The principles given in this paper were applied to the synthesis of such a log. The results are shown in Fig 19*b*, while the resistivity ratios used and a schematic geological column are given in Fig 19*a*. The resistivity values were taken from the electric log recorded in the field.

When computing the S.P. log for the impervious beds shown at 2940, 2970, and 3005 ft, the thickness of each bed, determined from the recorded log, was taken to be respectively $4d$, $14d$, and $5d$. The static S.P., opposite the permeable section, was considered to correspond to the permeable bed line, already mentioned. The static S.P. for the 3 impervious beds was assumed at first to correspond to the shale line. To determine the amplitude of the inverted peaks on the computed log, it was considered that the resistivity for the formations bounding each impervious bed could be taken as the same as the résistivity of each bed. The shape of the curve was modi-

fied, however, to take into account the variations in resistivity outside of the impervious beds.

pseudo-static S.P. of half the maximum emf, such as might occur for a mixture of shale and permeable lime.



—— STATIC S.P. DIAGRAM ——— S.P. LOG (x) RESISTIVITY IN UNITS OF MUD RESISTIVITY. DIAMETER OF HOLE = 9"

FIG 19—FIELD EXAMPLE OF S.P. LOG RECORDED OPPOSITE A LONG PERMEABLE SECTION.

The first attempt indicated a good correspondence between the computed log and the recorded log opposite the two lower impervious beds. The bed at 2940 ft gave, however, a deflection twice as large in amplitude as the one recorded. The assumption was then made that the bed had a

The transition zone at the top of the lime was drawn on the basis of a potential drop of 110 mv, using the resistivity ratios indicated. It is seen that the inflection point at the top of the lime formation is not at the middle point of the deflection, but closer to the shale base-line side as should be ex-

pected, because the shale is more conductive than the formation underneath. A closer examination of the actual electric log, however, indicates that the assumption of a sharp boundary is an oversimplification.

A computed S.P. log was given for this example, in order to show one possible solution of a section of a particular S.P. log. Other reasonable assumptions could also be made, depending upon the judgment of the computer and information from the actual physical data on hand. The indications are that, even though the conditions of uniform resistivities postulated by the mathematical computations are only approximately met here (leave alone such other phenomena, as the effect of invasion), it is nevertheless possible to construct an S.P. log giving close similitude in shapes and maxima to a simple field example.

Shaly Oil Sand

An instance of a shaly oil sand is given in Fig 20. A comparison of the field log with the computed S.P. charts for clean sands shows that the computed peaks are too sharp to match those of the field log, particularly in the upper section (8930 to 8955 ft and 8970 to 8990 ft), when using the thicknesses determined by the inflection points and the resistivity ratios given by the resistivity log. Assuming that the total emf is given by the total deflection in the lower salt-water section, a pseudo-static S.P. is required to explain the S.P. log for the upper sands.

Such a pseudo-static S.P. suggests that the sands are shaly, and in fact this is borne out by the core record. The required value for the pseudo-static S.P. can be explained by two different sets of conditions:

1. The sands are water bearing and they contain a sufficient proportion of shaly material to explain the reduction of the static S.P. with respect to the total emf.

2. The sands are not only shaly but they also contain oil or gas, and, in that case the proportion of shaly material required to explain the reduction in the static S.P. is less than in case 1.

The resistivity of the sands, as given by the resistivity log, is too high to be compatible with case 1, and therefore the interpretation should be that the sands are oil or gas bearing. This is confirmed by the analysis of the cores.

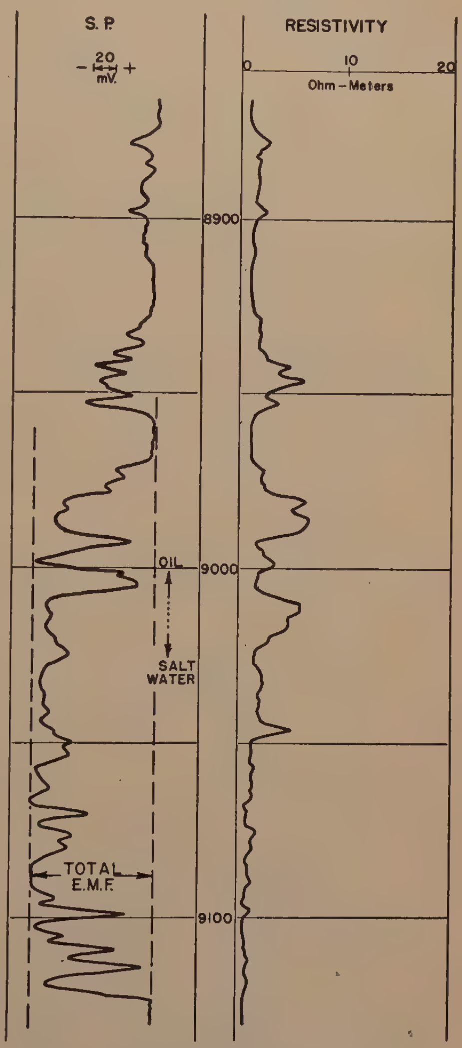


Fig 20—Field example of S.P. log showing shaly oil sand.

Base Line Shifts

The examples of Figs 21 and 22 show base line shifts. The shales in the upper parts of the log are known to be of different character from the shales present in the lower sections.

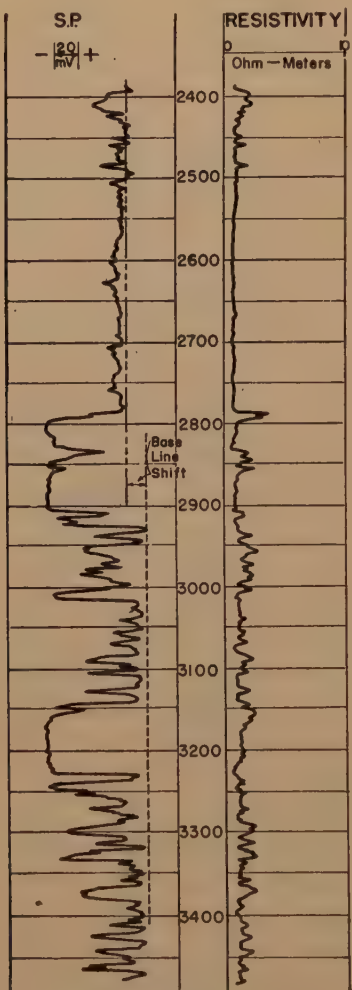


FIG 21

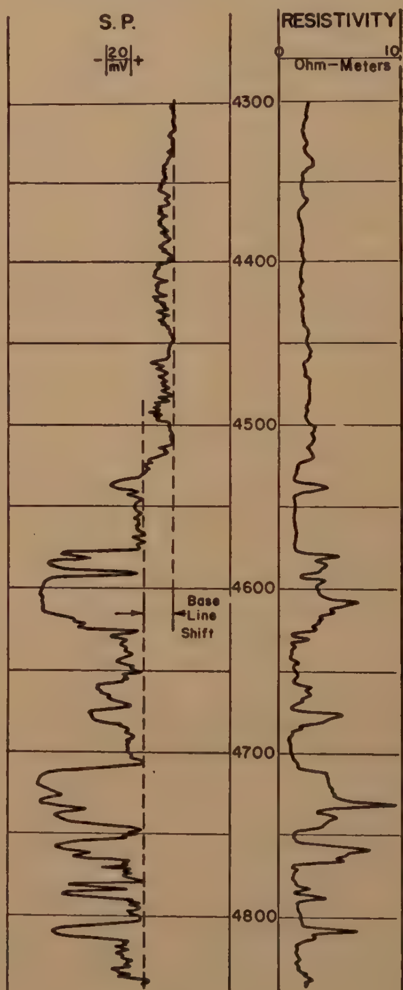


FIG 22

FIGS 21 AND 22—FIELD EXAMPLES OF S.P. LOGS SHOWING BASE LINE SHIFT.

In these cases, the static S.P. for the different categories of shale are sufficiently different to shift the base line. The level where the shift occurs constitutes an horizon marker, and thus provides an identification of the geological section through the use of the electric logs.

Permeable Zones in Lime

An example illustrating the correspondence between the S.P. log recorded at an increased sensitivity (amplified S.P.) and the core record for a section of lime is given in Fig 23.

It is seen that the zones otherwise known as permeable, are indicated on the log by

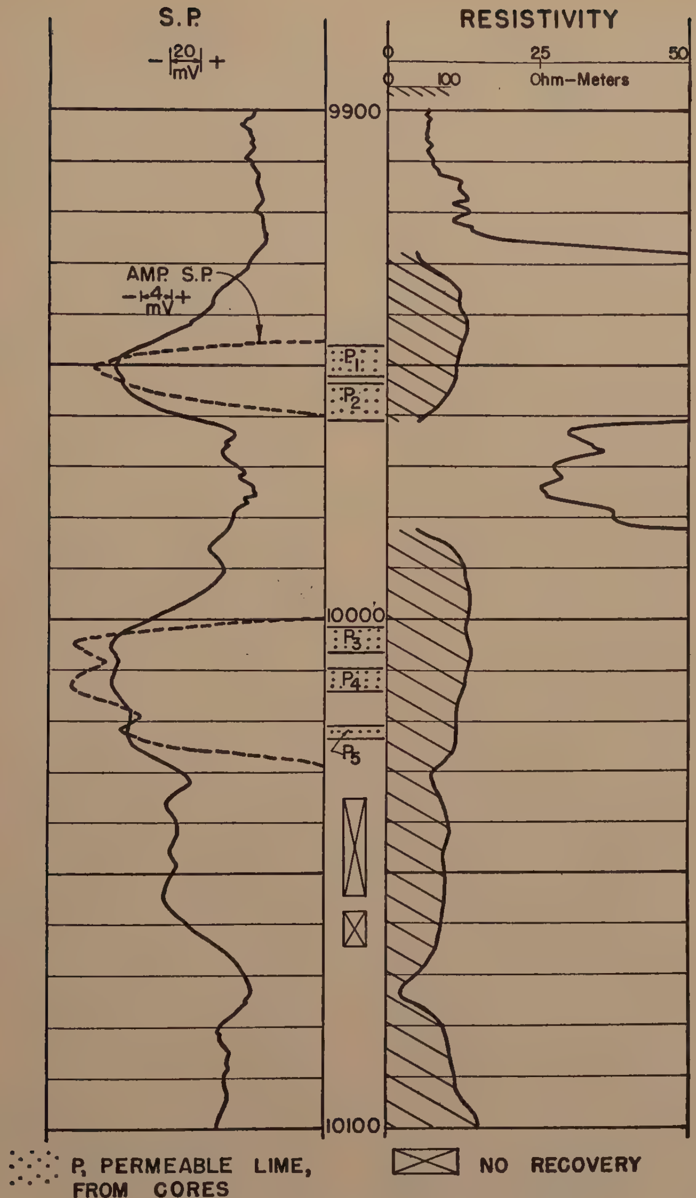


FIG 23—FIELD EXAMPLE OF S.P. LOG IN LIMESTONE.

curved parts with convexity toward the negative.

Conclusions

The present paper presents a theory of the S.P. log which might serve as a guide for interpretation, and as a foundation for further discussion on the subject.

The static S.P. diagram, which may seem too abstract at first, has been introduced because it is a convenient way to represent the emf involved. Some of these emf are of electrochemical nature, and occur at the boundaries between the mud and the formations, as well as at the boundaries between the formations themselves. Some others are due to the electrofiltration phenomena, and occur across the mud cake. Together they generate S.P. currents which flow in the ground, and close their path through the mud in the drill hole. In so doing they produce, in the mud, by ohmic effect, potential differences which are recorded to obtain the S.P. log.

Some potential drops by ohmic effect also occur in the formations, especially when the beds are thin and resistive; as a result the potential differences recorded on the S.P. log are not always equal to the total emf involved. The amplitude of a deflection is therefore not a measure of the total emf, except in the case of thick and conductive beds. In the general case, the amplitude is affected by many other factors besides the value of the total emf; namely, the thickness of the beds, their resistivity and that of the mud, colloidal content of the beds, the diameter of the hole, and the depth of invasion of the mud filtrate.

Extensive computations have been made to analyze the behavior of the S.P. log in well-determined and idealized conditions. When accurate computations were practically impossible schematical equivalences have been used. In spite of the assumptions and approximations made, the results obtained are of great value for the practical analysis of the S.P. logs, and should greatly increase the amount of information that can be obtained from such logs.

In spite of the complexity of the problem, a number of simple conclusions can be derived and used as a practical guide for the interpretation of the S.P. logs; namely:

1. The S.P. log is essentially a good detector of permeable beds, which, under normal conditions, correspond to negative peaks. It does not, however, measure the value of the permeability or of the porosity, and in fact makes little differentiation between highly permeable beds and strata whose permeability is too low to be of commercial value.

2. The boundary between a permeable bed and an impervious bed is characterized by an inflection point on the S.P. log. This inflection point does not correspond to half deflection when the resistivities of the two beds in contact are different, or when one of the beds is thin. For the boundary of two thick beds the inflection point is nearer to the plateau corresponding to the more conductive of the two beds.

3. When permeable beds are bounded by highly resistive formations, as in limestone fields, the corresponding peaks spread appreciably beyond the boundaries. The boundaries cannot anymore be determined with good accuracy without the help of the resistivity log. The permeable beds, however, are characterized on the S.P. log by slope changes, or curvatures, with the convexity toward the negative. Conversely impervious beds of low resistivity are characterized by slope changes, or curvatures, with the convexity toward the positive. Highly resistive formations correspond to substantially straight parts of the S.P. log.

4. The S.P. log has a symmetrical nature. When the permeable beds are reasonably clean, are of sufficient thickness, and contain the same interstitial water, they furnish a base line which is just as good as the shale line.

5. The total emf is represented on the S.P. log by the amplitude recorded on thick sands that are known to be substantially clean, and to contain the same type of interstitial water. When the amplitude on other beds is to be used for analysis, it should not be computed in millivolts, but rather in percentage of the total emf.

6. For thin clean sands, the amplitude of the S.P. peaks, although influenced by several additional factors, may be used to get an approximation of the thickness, provided the resistivity of each sand and its adjacent formations are approximately the same.

7. Sands containing colloidal material, or sandwiches of thin strata of sand and shale, behave as if the emf involved were a function of the percentage of shale or colloidal material. Other conditions being the same, the apparent emf, also called pseudostatic S.P., decreases where the oil saturation in these sands increases, even though their colloidal content is only a few per cent. Accordingly, in the case of thick beds, the amplitude may be used to indicate approximately the percentage of colloidal material, and to assist in the discrimination between oil-bearing and water-bearing sections of a shaly sand.

8. The area under the S.P. log, that is the area between the S.P. log and the base line, may in favorable cases, where the resistivity of the formation is substantially constant, give a useful indication of the respective proportions of permeable and impervious beds in a given interval.

Acknowledgments

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Stresses Around a Deep Well

By A. J. Miles* and A. D. Topping†

(Tulsa and Los Angeles Meetings, October 1947)

Abstract

In this paper, the theory of elasticity has been applied to the rock about a deep well. It is assumed that the rock has a modulus of elasticity and a Poisson's ratio and that the theory of elasticity applies. It is necessary to know or assume the state of stress existing in the rock before it is penetrated by the well drill.

The application of this theory indicates that stress concentration of shear, tensions, and compressions about the bore hole are of a high order. This is particularly true when a horizontal compressive stress exists in one direction only in the formation before drilling. If such an initial state of stress exists before drilling, then the rock will have stress concentrations of both tension and compression at the same elevation and of such magnitude that failure of the rock is likely. Accompanying these is a shearing stress of large proportion which is likely to produce spalling of the well walls. Internal pressure applied to the well bore will relieve the extreme compression but not the tension and has little effect upon the shear. Plastic deformation of the rock through a geological time tends to mitigate the stress concentrations.

Introduction

It has long been known that the stresses about holes and re-entrant corners of elastic solids under the influence of loads are different and generally more intense than those imposed upon the body elsewhere. Stress concentration at a re-entrant corner can be reduced by increasing the radius of the fillet at the corner. Stress concentration at the end of a crack in a plate undergoing either tension or compression can be relieved appreciably by drilling a hole at the very end of the crack. Also, stresses can be increased in an elastic body in tension or compression by making a hole in it. The stress concentration is greatest at the edge of the hole.

Considerable knowledge of the stresses which exist about the bore hole of a deep well may be had by applying our knowledge of engineering mechanics; or more particularly the theory of elasticity. It is, of course, necessary to make the assumption that the rock is elastic and behaves as an elastic solid, that is, that it obeys Hooke's law, has a modulus of elasticity, and a Poisson's ratio. It is also necessary to know, or assume, the state of stress which exists in the rock prior to the penetration of the drill. With this knowledge it is possible to compute the stresses about the bore hole.

The problem can be simplified by considering several simple cases separately and then by applying the principle of superposition to solve the more complex cases which are made up of the simpler ones.

Case 1—Rock Strata in Compression Penetrated by a Hole

This case was first worked out by G. Kirsch* for structural material, but applies equally well to a horizontal rock strata in a state of compression in one direction

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* G. Kirsch: V.D.I. (1898) 42.

only and penetrated by a drill. It is further assumed that the rock is free to become slightly thicker, according to Poisson's law, with changing stresses. Only the results of the analytical solution are given here. The reader is referred to Appendix B for an explanation of symbols. The stresses about the borehole are:

$$\left.\begin{aligned}\sigma_r &= \frac{S}{2}\left[\left(1 - \frac{a^2}{r^2}\right) + \cos 2\theta \left(1 - 4\frac{a^2}{r^2} + 3\frac{a^4}{r^4}\right)\right]\\ \sigma_\theta &= \frac{S}{2}\left[\left(1 + \frac{a^2}{r^2}\right) - \cos 2\theta \left(1 + 3\frac{a^4}{r^4}\right)\right]\\ \tau_{r\theta} &= -\frac{S}{2}\left(1 + 2\frac{a^2}{r^2} - 3\frac{a^4}{r^4}\right)\sin 2\theta\end{aligned}\right\} \quad [1]$$

At the edge of the hole, $r = a$, which gives:

$$\left.\begin{aligned}\sigma_r &= 0\\ \sigma_\theta &= S - 2S\cos 2\theta\\ \tau_{r\theta} &= 0\end{aligned}\right\} \quad [2]$$

The tangential stress, σ_θ, may be seen to be a maximum when $\theta = \frac{\pi}{2}$ or $\frac{3\pi}{2}$, which gives $\sigma_\theta = 3S$. This stress occurs on a line through the center of the hole perpendicular to the direction of the stress S. This line is an axis of symmetry, which makes $\tau_{r\theta} = 0$ and σ_r and σ_θ principal stresses. The general equations for stress along this line are:

$$\left.\begin{aligned}\sigma_r &= \frac{3S}{2}\left(\frac{a^2}{r^2} - \frac{a^4}{r^4}\right)\\ \sigma_\theta &= \frac{S}{2}\left(2 + \frac{a^2}{r^2} + 3\frac{a^4}{r^4}\right)\\ \tau_{r\theta} &= 0\end{aligned}\right\} \quad [3]$$

It should also be noted that when $\theta = 0$ or π, $\sigma_\theta = -S$, which indicates a compressive stress at right angles to the direction of the original stress and equal to it in magnitude. If the initial stress were compressive, this stress would be tensile. The general equations for the stresses on the line $\theta = 0$ or π are:

$$\left.\begin{aligned}\sigma_r &= \frac{S}{2}\left(2 + \frac{3a^4}{r^4} - \frac{5a^2}{r^2}\right)\\ \sigma_\theta &= \frac{S}{2}\left(\frac{a^2}{r^2} - \frac{3a^4}{r^4}\right)\\ \tau_{r\theta} &= 0\end{aligned}\right\} \quad [4]$$

The maximum shearing stress is also of interest. It is seen that the difference between σ_r and σ_θ is the greatest when $\theta = \frac{\pi}{2}$. Since σ_r and σ_θ are the principal stresses,

$$\tau_{\text{max.}} = \frac{\sigma_r - \sigma_\theta}{2} = -\frac{S}{2}\left(1 - \frac{a^2}{r^2} + 3\frac{a^4}{r^4}\right) \quad [5]$$

from which $\tau_{\text{max.}} = -1.5S$ at the edge of the hole.

To put these equations in words, if the strata penetrated by the drill is in compression in an east and west direction only, there is, as a result of this penetration, a compressive stress concentration on a line up the north and south sides of the hole equal to three times the initial compressive stress in the rock. Also, along this line there exists a shear stress equal to one and one-half times the initial compressive stress which acts on vertical planes inclined 45° to the radius of the hole. This shearing stress tends to cause the rock to spall off the side of the borehole in long vertical pieces. On the east and west sides of the borehole, as a result of drill penetration there is a tensile stress equal to the initial compressive stress in the rock. This, of course, tends to make a vertical fracture in the rock. There is also a shear stress as before, but of trivial proportions.

Internal pressure applied within the borehole would superimpose upon the stress already existing, additional stresses which may be computed by thick cylinder formulas. Among these additional stresses is a uniform tension around the borehole, tending to open a vertical seam.

Case 2—A Horizontal Rock Strata in Uniform Compression from All Directions in Its Plane, and Penetrated by a Drill

This is simply the case of a thick cylinder with an external pressure equal to the initial compressive stress in the rock. The formula for the stresses about the borehole when the external pressure is p_0 and the internal pressure is zero is:

$$\left.\begin{aligned}\sigma_r &= \frac{a^2b^2p_0}{r^2(b^2-a^2)} - \frac{p_0b^2}{b^2-a^2}\\ \sigma_r &= \frac{p_0b^2}{b^2-a^2}\left(\frac{a^2}{r^2}-1\right)\end{aligned}\right\} \quad [6]$$

$$\sigma_\theta = -\frac{p_0b^2}{b^2-a^2}\left(\frac{a^2}{r^2}+1\right) \quad [7]$$

$$\left.\begin{aligned}\tau_{\text{max.}} &= \frac{p_0b^2}{2(b^2-a^2)}\left(\frac{a^2}{r^2}-1+\frac{a^2}{r^2}+1\right)\\ \tau_{\text{max.}} &= \pm\frac{a^2b^2p_0}{r^2(b^2-a^2)}\end{aligned}\right\} \quad [8]$$

If the external radius, b, is large in comparison with the radius of the well, a, the stresses approach the values:

$$\left.\begin{aligned}\sigma_r &= p_0\left(\frac{a^2}{r^2}-1\right)\\ \sigma_\theta &= -p_0\left(\frac{a^2}{r^2}+1\right)\\ \tau_{\text{max.}} &= \pm\frac{p_0a^2}{r^2}\end{aligned}\right\} \quad [9]$$

Note that $\sigma_r + \sigma_\theta$ is a constant throughout the formation. Therefore, there is a uniform extension in the vertical direction according to Poisson's law, and no local tendency for the rock to thicken as a result of the borehole. This fact will be seen later to be important in the analysis of stress due to vertical loads.

At the borehole, Eq. 9 reduces to:

$$\left.\begin{aligned}\sigma_r &= 0\\ \sigma_\theta &= -2p_0\\ \tau_{\text{max.}} &= \pm p_0\end{aligned}\right\} \quad [10]$$

Hence, there is a compression σ_θ equal to twice the initial stress existing in the formation before it was drilled, and a shearing stress tending to spall the borehole walls as before equal to the initial stress.

Case 3—Uniform Pressure in the Borehole

In the case of a uniform horizontal strata, impervious to fluid and subjected to pressure within the borehole, the stresses about the well bore are given by the thick cylinder formula with the external radius made to approach infinity. The stresses are a maximum at the borehole and given by:

$$\left.\begin{aligned}\sigma_r &= -p_i\\ \sigma_\theta &= +p_i\\ \tau_{\text{max.}} &= \pm p_i\end{aligned}\right\} \quad [11]$$

Thus, we see that a cylindrical well with impervious walls and subjected to an internal pressure has compressive radial stress equal to the internal pressure, a tensile circumferential stress equal in magnitude to the internal pressure and a maximum shear equal to the internal pressure on vertical planes which make an angle of 45° to the radius of the borehole. This tends to spall the walls in a manner similar to the two previous cases.

Case 4—Stresses in a Horizontal Strata Due to Overburden

Stresses in a horizontal strata, due to the weight of the formation above, produce simple vertical compressive stresses where the strata under consideration is free to expand horizontally as the strata above are laid down. No stress concentration at the well result as a consequence of drilling. However, if a compressive force is applied to a body, it, of course, shortens in the direction of the applied stresses and becomes longer laterally. If the body is not free to move laterally, compressive stresses result equal to the primary compressive stress multiplied by Poisson's ratio, or approximately 25 pct of the primary stress. This secondary stress can be taken care of by application of case 2.

Case 5—Thick Strata Penetrated by a Drill

In cases 2, 3, and 4, it was found that the sum of the horizontal principal stresses was constant throughout the formation. This means that any change as a result of drilling and/or pressure changes within the borehole resulted in a tendency for the entire strata to become thicker or thinner uniformly throughout its entire extent. Imaginary planes within the strata have no tendency to become warped or distorted at or near the well as a result of drilling or pressure changes within the borehole.

In case 1 above, where the strata is in compression in its own plane and in only one direction, as for example, in an east and west direction only, the sum of the principal stresses is no longer constant and high stress concentrations result. The stress factor is three at two points at the borehole and minus one at two others. This tends to cause the strata to become thicker in the former and to become thinner in the latter. This offers no difficulty in the solution of problems dealing with thin plates or strata, because the change in thickness is small and the plates are not constrained. However, in strata several hundred feet thick, this change in thickness, if it were not constrained, would be cumulative and amount to several inches. It may be computed by the simple formula:

$$\epsilon_1 = \frac{\mu}{E}\, 2S \quad \text{inches per inch of formation} \qquad [12]$$

on the sides of the hole where the concentration factor is 3, and:

$$\epsilon_2 = \frac{-\mu}{E}\, 2S \quad \text{inches per inch of formation} \qquad [13]$$

where the stress concentration factor is -1.

Since the horizontal stress in the rock before drilling was S and became $3S$ and $-S$ at points on the borehole after drilling, the change is $2S$ and $-2S$, respectively. This tendency of certain elements of the borehole to shorten, while others in the same well tend to lengthen, is strictly a local phenomenon. The surrounding material gives support to the highly stressed elements and prevents the elongation indicated by Eq 12 and Eq 13.

If the material surrounding the well provides sufficient support to keep the formation from distorting in this manner, and this certainly seems to be a reasonable assumption, the vertical stresses imposed are just sufficient to restore this distortion to zero. Thus, the maximum additional vertical stress concentration is:

$$\Delta\sigma_z = \pm 2\mu S \qquad [14]$$

The plus sign is used at the points where the strata tends to become thinner as a result of tension, hence a tension is required to maintain thickness. A minus sign is used where the stress concentration is three and the formation tends to thicken. Therefore, we may express the total stress existing at the borehole as follows:

$$\begin{aligned} \sigma_{\theta_{\text{max.}}} &= -3S \\ \sigma_{z_{\text{max.}}} &= -z\rho - 2\mu S \\ \sigma_{z_{\text{min.}}} &= -z\rho + 2\mu S \end{aligned} \qquad [15]$$

Where z is the depth of the formation and ρ is the density so that $z\rho$ is the vertical pressure due to the overburden, the minus sign indicates compression.

These stresses are principal stresses since they are on planes of symmetry, hence the maximum shear can be found by taking one-half of the difference between the largest and smallest principal stresses.

Application of Formulas to Numerical Problems

(*a*) Consider a depth of 10,000 ft with $\rho = 1$ psi per foot of depth and no pressure within the well, then

$$\sigma_z = -z\rho = -10{,}000 \times 1 = -10{,}000 \text{ psi} \qquad [16]$$

at all points within the formation at this depth. If the formation was, and still is, rigidly confined horizontally as the overburden was laid down and has experienced no plastic deformation, then:

$$\left.\begin{aligned} \sigma_\theta &= 2\mu\sigma_z = -2 \times 0.25 \times 10{,}000 \\ &= -5000 \text{ psi} \\ \tau_{rz_{\text{max.}}} &= -\frac{10{,}000 + 5000}{2} \\ &= \pm 2500 \text{ psi} \end{aligned}\right\} \quad [17]$$

If there is no restraint to horizontal expansion as the overburden is laid down,

$$\sigma_r = \sigma_\theta = 0 \quad [18]$$

Partial restraint or plastic deformation will result in values for σ_r and σ_θ between those given by Eq 17 and Eq 18.

(*b*) If a pressure of, say, 6000 psi is applied at the sand face within this well, the stresses resulting are by Eq 11:

$$\left.\begin{aligned} \sigma_r &= -6000 \\ \sigma_\theta &= 6000 \\ \tau_{r\theta} &= 6000 \end{aligned}\right\} \quad [19]$$

and must be added algebraically to the above so that the resultants now are:

$$\begin{aligned} \sigma_r &= 0 - 6000 = -6000 \text{ psi} \\ \sigma_\theta &= -5000 + 6000 = +1000 \text{ psi} \\ \sigma_z &= 10{,}000 + 0 = -10{,}000 \text{ psi} \\ \tau_{\theta z_{\text{max.}}} &= -\frac{10{,}000 - 1000}{2} = 5500 \text{ psi} \end{aligned} \quad [20]$$

(*c*) If at 10,000 ft there is a compressive stress of 5000 psi in an east and west direction, but none north and south, the formula of case 5 is used:

$$\left.\begin{aligned} S &= -5000 \text{ psi as given above.} \\ \sigma_{\theta_{\text{max.}}} &= -3S = -15{,}000 \text{ psi at the north and south edges of the holes.} \\ \sigma_{z_{\text{max.}}} &= -zp - 2\mu S = -10{,}000 - 2 \times 0.25 \times 5000 \\ &= -12{,}500 \text{ psi at the north and south edges.} \\ \sigma_{z_{\text{min.}}} &= -zp + 2\mu S = -10{,}000 + 2 \times 0.25 \times 5000 \\ &= -7500 \text{ psi at the east and west edges.} \\ \sigma_{\theta_{\text{min.}}} &= -S = 5000 \text{ psi at the east and west edges of the hole.} \\ \sigma_r &= 0 \text{ at all sides.} \\ \tau_{\theta z_{\text{max.}}} &= 6250 \text{ psi at the east and west edges.} \end{aligned}\right\} \quad [21]$$

Where internal pressure is applied to the well, results are computed as above and added algebraically.

These equations indicate that stresses, shear, tension, and compression, of a high order are highly probable at the walls of the borehole, and that their value depends primarily upon the depth and weight of the overburden and upon the relative values of the horizontal stresses within the rock before the drill penetrated it. The worst stress condition results from an initial horizontal compression in the rock before drilling. Drilling causes stress concentrations of both tension and compression at the same elevation of such magnitude that failure of the rock is likely. Accompanying these in a shearing stress of large proportion which also produces spalling of the well walls. Internal pressure applied to the well bore will relieve the extreme compression but not the tension and has little effect upon the shear. Plastic deformation of the rock through geological time tend to mitigate the stress concentrations.

Acknowledgment

The authors wish to express thanks to Mr. George. S. Bays, of the Stanolind Oil and Gas Company for suggesting this problem and for helpful advice.

Appendix A

Definition of Terms

Constraint—confinement; resistance to expansion or contraction.

Plane strain—deformation restricted to directions parallel to a single plane.

Plane stress—complete freedom of expansion and contraction perpendicular to a plane, so that stresses parallel to the plane do not affect stresses perpendicular to the plane.

Principal stresses—normal stresses corresponding to directions of zero shear.

Spalling—splitting off of pieces from a rock face.

Uniform expansion—deformation perpendicular to a plane restricted only to the extent of being held to the same magnitude over the given area.

Appendix B

Symbols

r, θ, z	Cylindrical coordinates.
σ_r, σ_θ, σ_z	Radial, tangential, and vertical normal stresses in cylindrical coordinates.
τ	Shearing stress.
$\tau_{r\theta}$, τ_{rz}, $\tau_{\theta z}$	Shearing stress components in cylindrical coordinates.
a	Inside radius of a hollow cylinder or borehole.
b	Outside radius of a hollow cylinder.
p_0	External pressure on a hollow cylinder.
p_i	Internal pressure in a hollow cylinder.
S	Initial uniform stress perpendicular to the axis of the hole.
ϵ_x, ϵ_y, ϵ_z	Unit elongations in rectangular components.
ρ	Weight of overburden per foot of depth.
μ	Poisson's ratio.
E	Modulus of elasticity in compression or tension.

Appendix C

There is another table,* taken from Bauschinger, showing that the shearing strength parallel to the bedding plane of the rock runs about 60 to 70 pct of the value perpendicular to the bedding plane.

Stress-strain diagrams on pp. 256–257, Johnson,* show that stone does not strictly follow Hooke's law; however, the tangent modulus actually increases with load, rather than decreases, the curves being quite straight near the ultimate. Lewis' results† show fairly straight stress-strain curves with a proportional elastic limit very close to the ultimate. In either case, the assumption of an elastic material seems reasonably close.

Values for all properties of stone vary widely with different specimens; the compressive strength of limestone, for instance, may vary from 4000 to 20,000 psi. Consequently, for accurate results, sample tests must be made of the rock at the place in question. With regard to the compressive strength of stone, it is undoubtedly considerably greater when confined on all sides than when unconfined. The values in Table 1 were from tests on unconfined stone.

† Walter E. Lewis: The Mechanical Properties of Mine Rocks and a Standardized Test Procedure for Their Determination. Thesis, Missouri School of Mines and Metallurgy, Rolla, Mo.

Table 1—*Mechanical Properties of Rocks*[a]

Rock Type	Average Ultimate Compressive Strength, Psi	Average Ultimate Tensile Strength, Psi	Average Ultimate Shearing Strength, Psi	Poisson's Ratio, μ	Modulus of Elasticity, E^b
Marble	13,000	450	1,300	0.27	8,000,000
Limestone	9,000	300	1,350	0.26	8,460,000
Sandstone	11,000	200	1,200	0.23	3,000,000
Granite	20,000	650	2,000	0.21	7,300,000

[a] J. B. Johnson, M. O. Withey and James Aston: Johnsons Materials of Construction. 8th ed. pp. 254–258 (1939). New York. Wiley and Co. Values given in the table are approximate averages of values from Table 4, p. 255.

[b] Marks: Mechanical Engineers' Handbook.

Effect of Antifreeze Agents on the Formation of Hydrogen Sulphide Hydrate

By Donald C. Bond* and Nelson B. Russell*

(Dallas and Los Angeles Meetings, October 1948)

Abstract

The effects of various antifreeze agents on the formation of hydrogen sulphide hydrate have been studied. On a molar basis the relative lowering of T_M (the maximum temperature at which solid hydrogen sulphide hydrate can exist in equilibrium with the given solution) for the various agents is: sodium chloride 1.00, calcium chloride 1.71, methyl alcohol 0.57, ethyl alcohol 0.68, ethylene glycol 0.73, diethylene glycol 0.73, sucrose 0.87, dextrose 0.71. On a weight basis the relative lowering of T_M is: sodium chloride 1.00, calcium chloride 0.91, methyl alcohol 1.08, ethyl alcohol 0.89, ethylene glycol 0.69, diethylene glycol 0.41, dextrose 0.23, and sucrose 0.15.

Introduction

The solid hydrate of hydrogen sulphide, $H_2S \cdot 6H_2O$,[1] is in equilibrium with water and liquid hydrogen sulphide at 85°F at a partial pressure of hydrogen sulphide approximately equal to the vapor pressure of hydrogen sulphide at that temperature. At temperatures below 85°F, in the presence of excess hydrogen sulphide (greater than the amount required to react with the water present) the hydrate is in equilibrium with liquid hydrogen sulphide at approximately the vapor pressure of hydrogen sulphide.

In the presence of excess water, the solid hydrate is in equilibrium with liquid water, containing dissolved hydrogen sulphide, at a pressure lower than the vapor pressure of liquid hydrogen sulphide at the same temperature.[2] The lower the temperature, the greater the difference between the decomposition pressure of the hydrate and the vapor pressure of liquid hydrogen sulphide at that temperature.

Conditions conducive to the formation of solid hydrogen sulphide hydrate may exist in wells producing a gas containing a high percentage of hydrogen sulphide under high pressure, or in the lead lines from such wells. This paper gives the results of tests made with various antifreeze agents which might be useful in decomposing the hydrate or in preventing the formation of the hydrate of hydrogen sulphide

Apparatus

Fig 1 shows a diagram of the apparatus used. The sample under observation was contained in a glass tube 34 cm long, having a 6 mm id and a wall thickness of 2.5 mm. The lower end of this tube was closed with a plug of butyl rubber. The upper end of the tube was connected to a diaphragm gauge, with a stainless steel diaphragm, a manometer, a vacuum pump, and a cylinder of hydrogen sulphide.

The tube was held nearly horizontal, with the liquid resting along the lower side of the tube. It was found that when the tube was held in a vertical position, it broke with explosive violence as soon as it became filled with solid hydrate. Presumably this was caused by the expansion which occurred on solidification of the hydrate. The difficulty disappeared when the tube was held in an inclined position during the tests.

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[1] References are at the end of the paper.

The liquid in the tube was stirred by a steel rod 4 mm in diameter and 6 cm long, actuated by means of an electromagnet which encircled the glass tube. The electro-

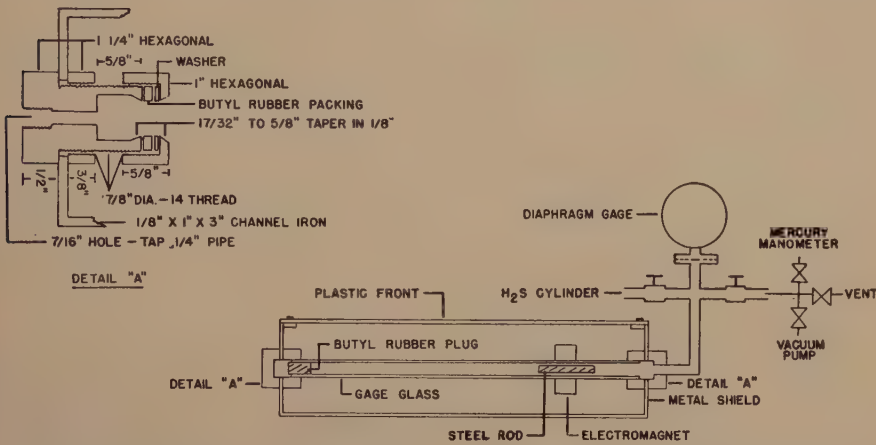

FIG 1—APPARATUS FOR DETERMINATION OF DECOMPOSITION POINT OF H_2S HYDRATE.

magnet was connected to the 110 v ac line; when the circuit was alternately completed and broken, the oscillation of the steel rod stirred the liquid vigorously. The electromagnet could be moved along the tube to obtain stirring at any point.

For safety the glass tube was enclosed in a steel shield ⅛ in. thick, with a ⅛ in. transparent plastic front. The tube was illuminated by means of a small lamp placed inside the shield.

The tube was immersed in an oil bath cooled by a coil through which tap water was circulated, or cooled by dry ice, depending on the temperature required. Closer control of the temperature was obtained with the aid of a 500 w heater controlled by a De Khotinsky bimetallic regulator. Fluctuations in the temperature of the bath were less than 0.5°F. Since the electromagnet used for stirring became heated slightly on continuous use, it was used only occasionally and was moved away from the hydrate when not in use in order to prevent warming of the liquid and hydrate under observation.

PROCEDURE

By means of a pipette, 2 cc of the liquid under test was introduced into the glass tube. The tube was then connected to the gauge, manometer, vacuum pump, and H_2S cylinder, after which it was placed in the oil bath and evacuated to 40-mm pressure to remove most of the air. In the case of the alcoholic solutions the apparatus was cooled to 0°C before being partially evacuated. Hydrogen sulphide was admitted to the system and the tube was again evacuated to 40-mm pressure.

Hydrogen sulphide was then admitted to the system, with occasional stirring by means of the steel rod and electromagnet, until the solid hydrate formed. If necessary, the system was cooled to allow hydrate formation. Hydrogen sulphide was then vented very slowly until it was observed that the solid hydrate was beginning to decompose.

In the case of pure water, the pressure was released until a considerable amount of hydrate had decomposed. The pressure at this point was somewhat lower than the equilibrium pressure. However, on standing at constant temperature the system, containing liquid water (with dissolved H_2S), solid H_2S hydrate, and gaseous H_2S,

showed a slow increase in pressure. After the pressure had become constant, additional H_2S was bled off to cause a slight reduction in pressure. The system was allowed to stand. Generally it was observed that the pressure again rose to the same constant pressure that was first observed. This constant, reproducible pressure was taken to be the equilibrium pressure for the existence of liquid water (containing dissolved H_2S), solid H_2S hydrate, and gaseous H_2S in contact with one another at the given temperature.

In the case of pure water, the relative amounts of water and solid hydrate present at the time of observation were not important. In the case of an aqueous solution of an antifreeze agent, say alcohol, the test was complicated by the fact that the formation of an appreciable amount of the hydrate consumed some water, so that the remaining solution of alcohol was more concentrated than the original alcohol solution. Since there was no way of knowing the amount of hydrate present, the concentration of the alcohol solution in equilibrium with the hydrate could not be determined.

This difficulty was avoided by the following procedure, in the aqueous antifreeze solutions. Hydrogen sulphide was withdrawn at intervals and the pressure increase on standing was observed, as with pure water. As this continued, the hydrate slowly disappeared. The pressure observed at the point where the last trace of solid hydrate disappeared was taken as the equilibrium pressure for the solution at the given temperature.

The procedure was rather tedious. From 2 to 4 hr were required to determine a single equilibrium point with pure water, while 4 to 6 hr were required for each point in the case of the antifreeze solutions.

It is believed that the maximum possible error in the determination of the equilibrium points is about 1°C, with a corresponding error of about 5 to 15 psi in pressure, depending on the slope of the pressure-temperature curve for the hydrate at the point in question. With the sugar solutions the possible error is perhaps 1.5°C; apparently the high viscosity of the sugar solutions retards the decomposition of the hydrate when the pressure is reduced.

Table 1 gives the results obtained with distilled water, water from Worland Unit No. 3,* salt solutions, alcohol solutions, and glycol solutions. In the case of the glycol solutions only T_M (maximum temperature at which H_2S hydrate can exist) was determined, because of the difficulty of obtaining reliable equilibrium points with these solutions.

Results

Table 1 gives the results of observations made with various antifreeze solutions. Fig 2 presents these results graphically and also gives values for the vapor pressure of liquid H_2S,[3] as well as data on the system (water-solid H_2S hydrate-gaseous H_2S) taken from the paper by F. E. C. Scheffer.[2]

The equilibrium pressure-temperature curve for each solution intersects the vapor pressure curve for liquid hydrogen sulphide at a point (P_M, T_M). It was found that the hydrate decomposed at temperatures above T_M, even in the presence of liquid H_2S. Table 1 also gives T_M for the various solutions tested.

Table 2 gives the lowering of T_M caused by various agents, in degrees per pound of agent per gallon of solution, as well as in degrees per mol of agent per liter of solution. Table 2 also gives the relative lowering of T_M caused by the various agents, on a molar basis as well as a weight basis, based on the effect of sodium chloride as unity.

In addition to tests on various antifreeze solutions, Table 1 and Fig 2 also give the results of tests on a representative sample

* Worland Unit No. 3, Worland, Wyoming, producing oil plus gas containing 29 mol pct H_2S, with a tubing pressure of approximately 2300 psi.

of water from a well producing a high concentration of H_2S (Table 1, No. 6). This water was separated from a sample of emulsion obtained just as a plug in the well broke loose.

hydrogen sulphide hydrate formation. Sucrose and dextrose are relatively ineffective; even in viscous 50 pct solution these sugars lower T_M only 12°F, for sucrose, or 18°F, for dextrose. The effects

TABLE 1—*Formation of H_2S Hydrate in Presence of Antifreeze Agents*

Number	Antifreeze Agent	Concentration Weight Per Cent	Temperature		Pressure, Psia[a]	T_M Maximum Temperature at which H_2S Hydrate can Form with Given Solution	
			Degree C	Degree F		Degree F	Degree C
1	None		10.0	50.0	45	85.1	29.5
	None		18.0	64.4	103		
	None		26.5	79.7	217		
	None		29.5	85.1	325		
2	Sodium chloride	10.0	1.7	35.0	30	71.0	21.7
	Sodium chloride	10.0	13.9	57.0	94		
	Sodium chloride	10.0	21.7	71.0	272		
3	Sodium chloride	26.4 (Satd.)	−4.0	24.8	61	44.2	6.8
	Sodium chloride	26.4	3.0	37.4	97		
	Sodium chloride	26.4	5.0	41.0	148		
	Sodium chloride	26.4	7.0	44.6	189		
	Sodium chloride	26.4	7.0	44.6	210		
4	Calcium chloride	10.0	1.7	35.0	25	72.0	22.2
	Calcium chloride	10.0	15.3	59.5	105		
	Calcium chloride	10.0	22.2	72.0	275		
5	Calcium chloride	21.1	−2.0	28.4	53	51.5	10.8
	Calcium chloride	21.1	4.0	39.2	95		
	Calcium chloride	21.1	8.0	46.4	133		
	Calcium chloride	21.1	11.0	51.8	216		
	Calcium chloride	21.1	11.1	52.0	227		
	Calcium chloride	36.0 (Satd.)	−7.8	18.0	128	18.0	−7.8
6	Water from Worland Unit No. 3[b]		15.0	59.0	69	83.5	28.6
	Water from Worland Unit No. 3[b]		20.8	69.5	140		
	Water from Worland Unit No. 3[b]		28.3	83.0	302		
7	Methyl alcohol	16.5	0.0	32.0	40	63.0	17.2
	Methyl alcohol	16.5	10.0	50.0	106		
	Methyl alcohol	16.5	16.9	62.5	217		
8	Ethyl alcohol	16.5	7.5	45.5	56	66.8	19.3
	Ethyl alcohol	16.5	14.7	58.5	128		
	Ethyl alcohol	16.5	18.6	65.5	215		
9	Ethylene glycol	48.5				38.0[c]	3.3[c]
10	Ethylene glycol	72.8					
11	Diethylene glycol	47.5				58.0	14.4
12	Diethylene glycol	71.2				30.0	−1.1
13	Diethylene glycol	85.5				15 (?)[d]	−9 (?)[d]
14	Diethylene glycol	95.0					
15	Dextrose	50.0	11.7	53.0	91	67.0	19.4
	Dextrose	50.0	16.1	61.0	145		
	Dextrose	50.0	19.4	67.0	255		
16	Sucrose	50.0	18.9	66.0	120	73.0	22.8
	Sucrose	50.0	20.5	69.0	199		
	Sucrose	50.0	22.8	73.0	280		
	Sucrose	50.0	22.8	73.0	277		

[a] Pounds per square inch absolute.
[b] These tests were made on the water separated from Sample No. 6B-2020, Emulsion from Worland Unit No. 3.
[c] Hydrate did not form at −30°F in presence of liquid H_2S in 5 hr.
[d] Hydrate did not form at −40°F in presence of liquid H_2S in 7 hr.

DISCUSSION OF RESULTS

For a given weight of antifreeze agent, sodium chloride, calcium chloride, methyl alcohol, and ethyl alcohol are about equally effective in lowering the temperature of of the glycols lie between those of the salts and the sugars tested.

Sodium chloride is the cheapest antifreeze tested. For the same effect, the costs of the various agents are approximately in

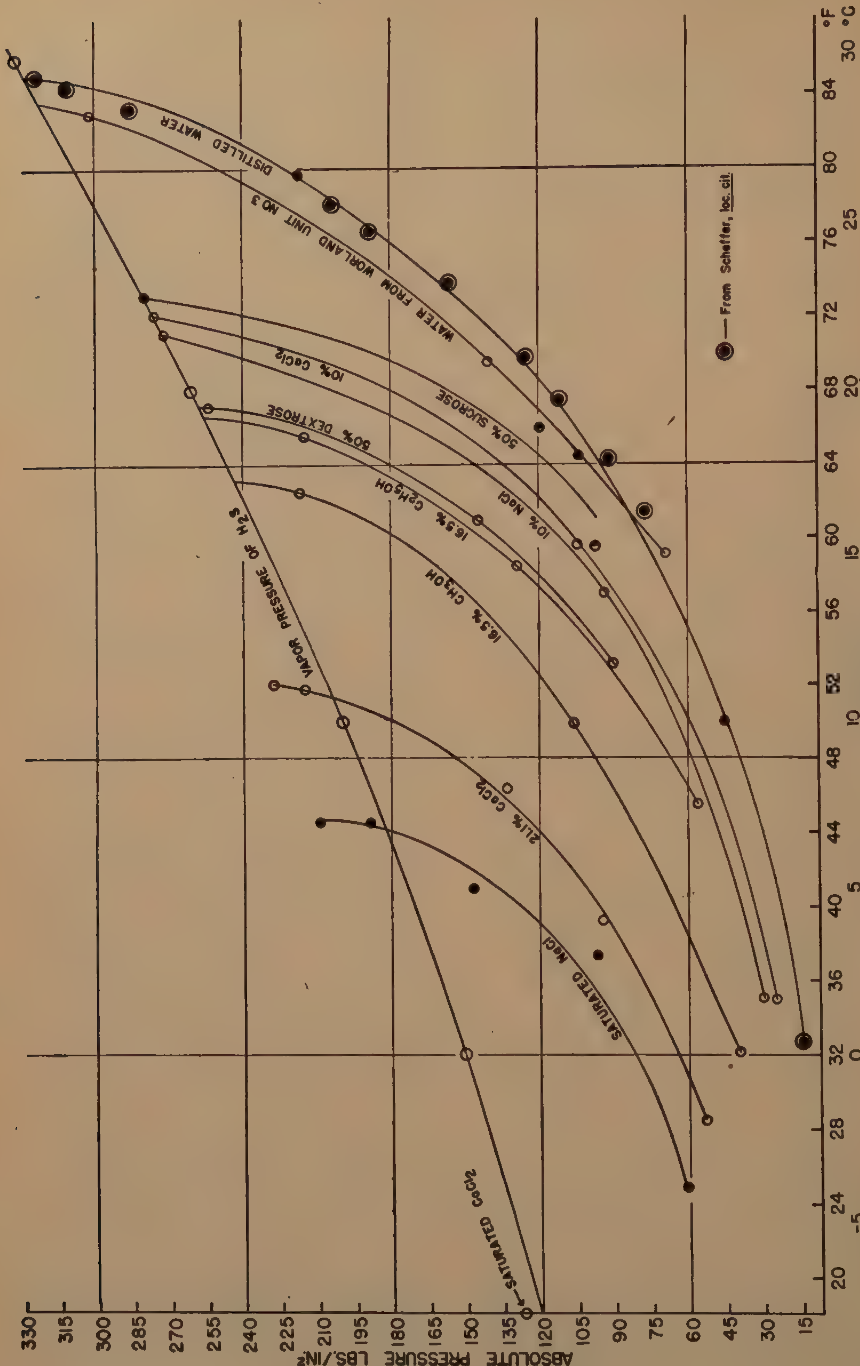

FIG 2—FORMATION OF H_2S HYDRATE IN PRESENCE OF ANTIFREEZE AGENTS.

the ratio: sodium chloride 1, calcium chloride 2, ethyl alcohol 3, methyl alcohol 8, ethylene glycol 20, diethylene glycol 33.

For a given weight of salt the effects of sodium chloride and calcium chloride are practically the same. However, because of the greater solubility of calcium chloride, T_M for saturated calcium chloride solution is much lower than T_M for saturated sodium chloride (18° vs 44°F).

The point of intersection of the hydrate curve for a given solution and the vapor pressure curve for H_2S (P_M, T_M) can be considered to be a quadruple point, since four phases are present: vapor, aqueous phase, liquid H_2S (containing dissolved water, and so on), and solid H_2S hydrate. This point differs from the quadruple point of Carson and Katz[4] in that only one hydrate-forming component is present, that is, H_2S, whereas Carson and Katz considered systems containing more than one hydrate-forming component. In the present tests the locus o the quadruple point was changed by varying the composition of the

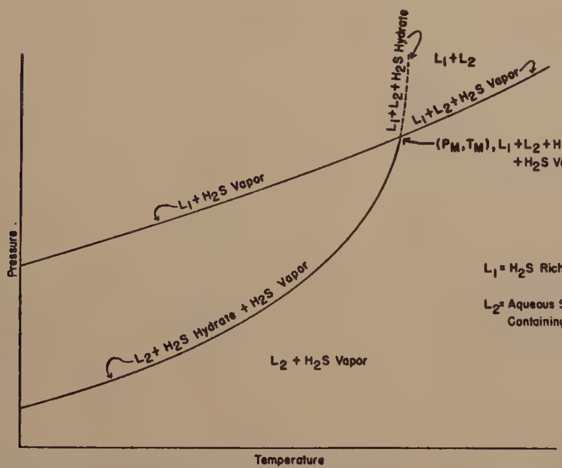

FIG 3—SCHEMATIC DIAGRAM SHOWING PHASE RELATIONS IN SYSTEMS CONTAINING H_2S AND AQUEOUS SOLUTIONS OF ANTIFREEZE.

TABLE 2—*Lowering of* T_M

(T_M is the maximum temperature at which solid H_2S hydrate can exist in equilibrium with given solution.)

Antifreeze	Lowering of T_M per Mol per Liter of Solution		Relative Lowering on Molar Basis	Lowering of T_M per Pound per Gallon of Solution		Relative Lowering on Weight Basis
	Degree F	Degree C		Degree F	Degree C	
Sodium chloride	7.7	4.3	1.00	15.7	8.8	1.00
Calcium chloride	13.3	7.4	1.71	14.3	8.0	0.91
Methyl alcohol	4.4	2.5	0.57	16.9	9.5	1.08
Ethyl alcohol	5.2	2.9	0.68	14.0	7.8	0.89
Ethylene glycol	5.6	3.1	0.73	10.9	6.1	0.69
Diethylene glycol	5.6	3.1	0.73	6.4	3.6	0.41
Dextrose	5.5	3.1	0.71	3.6	2.0	0.23
Sucrose	6.7	3.8	0.87	2.3	1.3	0.15

The results obtained with the sample of water from Worland Unit No. 3 are about what one would expect, since analysis of the water showed that it contained approximately 1 pct salt.

antifreeze solution, while Carson and Katz varied the composition of the hydrate-forming mixture, that is methane and propane.

Scheffer[2] claimed that his results indicated that the liquid H_2S, gaseous H_2S, H_2S hydrate curve was slightly below the H_2S-vapor pressure curve. The accuracy of our results is not great enough to distinguish between the vapor pressure curve for liquid H_2S and the locus of the quadruple point (H_2S vapor, liquid H_2S, solid H_2S hydrate, aqueous solution) for various antifreeze solutions.

For systems containing a vapor phase T_M is the maximum temperature at which H_2S hydrate can form. With systems containing no vapor phase it might be possible to obtain solid hydrate at temperatures slightly greater than T_M. However, the $L_1 - L_2$ hydrate curve for most systems is practically vertical, so for practical purposes, T_M can be considered to be the maximum temperature at which hydrate can form, unless inordinately high pressures exist.

A word about the interpretation of the curves given in Fig 2 may be helpful. For a given solution, solid H_2S hydrate will not form at temperatures and pressures represented by points below and to the right of the curve for that solution. In this region aqueous solution, containing dissolved H_2S, and gaseous H_2S are in equilibrium with one another. At points along the curve for a given solution, that solution, containing dissolved H_2S, is in equilibrium with solid H_2S hydrate and gaseous H_2S. This is shown schematically in Fig 3.

For a given aqueous solution, solid H_2S hydrate cannot exist indefinitely in contact with a vapor phase at pressures above the intersection of the hydrate curve for that solution and the vapor pressure curve for H_2S, since the pressure is lowered to the vapor pressure of H_2S by the condensation of liquid H_2S. It is possible to obtain metastable conditions at pressures slightly greater than the vapor pressure of H_2S, as shown by the upper parts of the curves for saturated sodium chloride and for 21.1 pct calcium chloride (Fig 2).

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Gravity Drainage Theory

By W. T. Cardwell, Jr.,* and R. L. Parsons,* Junior Members AIME

(Dallas and Los Angeles Meetings, October 1948)

Abstract

This paper presents a theory for estimating the rate of gravity drainage of a liquid out of a sand column. Account is taken of the variation in permeability to the liquid as the saturation in the upper part of the sand becomes less than 100 pct.

The theory is confirmed by previously published experimental data.

Introduction

Petroleum engineers have expressed the need for a theory of gravity drainage. Brunner,[1] in particular, has pointed out that some type of mathematical theory is necessary to begin the application of laboratory data to field problems.

Muskat and his associates[2,3,4] have recently made contributions to the theory of gas-drive behavior and have indicated an intention to apply their methods to water-drive systems. No theory of gravity drainage rates has been developed, however, and it seems desirable to formulate one at this time.

Differential Equations of Capillary Flow

The flow of liquids in partially saturated porous media has been studied by many investigators.[5–10] Richards[5] presented derivations of fundamental differential equations governing two-phase capillary flow; and used simplified forms of those equations in solving a steady-state problem. Muskat and Meres[6] presented and used equations different from those of Richards. Their equations did not explicitly involve capillary pressure gradients; but included, on the other hand, terms expressing the effects of the evolution of gas from the liquid phase during flow.

Leverett[8] stated in 1940 that "previous work on the flow of fluid mixtures in porous solids [had] failed adequately to account for all of the three influences that cause motion of the fluids: capillarity, gravity, and impressed external pressure differentials." Leverett's basic equations, however, were specialized forms of the general equations of Richards,[5] which had actually taken account of the three influences mentioned by Leverett, but had not been used in a problem involving all three.

The fact is that our knowledge of capillary flow and our ability to express this knowledge in differential equations exceed our ability to solve the equations except in a few cases. General differential equations have usually been of little more than formal value. In solving practical problems, it has been necessary to develop specific equations, preserving terms that involved the factors important in those problems, and purposefully neglecting other terms that were not of predominating influence. This is the method followed here. It is believed that the solution of the particular problem and the scheme of the solution itself are new.

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* California Research Corp., La Habra, Calif. (A subsidiary of Standard Oil Company of California).

[1] References are at the end of the paper.

Before leaving the subject of general equations, it seems appropriate to call attention to the ingenious electrical calculators developed during the recent war. Their most familiar application was perhaps the computation of shell and bomb trajectories. The complete equations of multiple-phase flow may be amenable to solution by specially designed electrical calculators, but this possibility has not been explored to date.

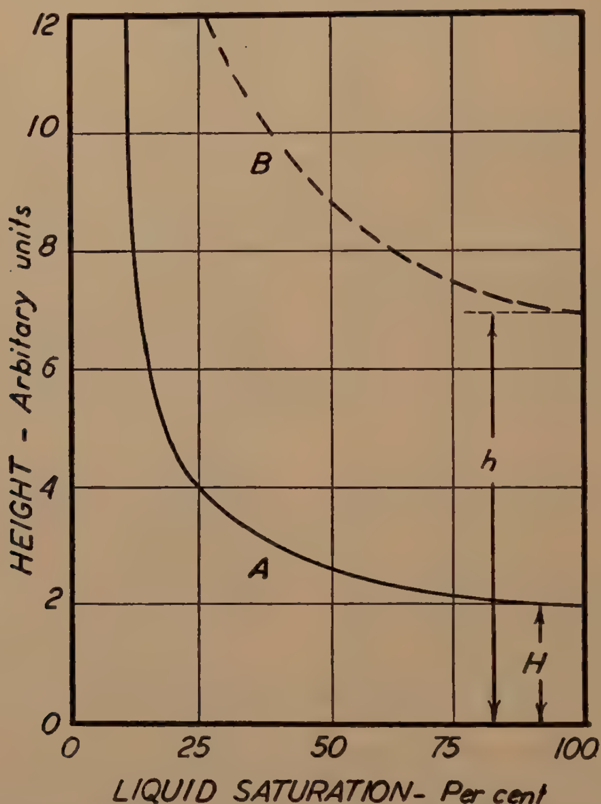

FIG 1—LIQUID DISTRIBUTION IN A COLUMN OF POROUS MEDIUM THAT HAS BEEN DRAINED.

THEORY

Fig 1, curve *A*, represents the type of liquid distribution that results when a vertical column of porous medium, open at the top and bottom, is saturated with liquid and then allowed to drain. At the lower end of the column there is a region of 100 pct saturation, analogous to the region of 100 pct saturation in a vertical glass capillary that has been filled with liquid and then allowed to drain. Above the 100 pct region is a transitional region of gradually decreasing saturation, which has no analogue in simple tubular drainage. Above this transitional region the saturation decrease per unit height becomes so small that finally there is a region of practically constant saturation.

Curve *A* of Fig 1 may be called the equilibrium drainage curve.

Now consider any other saturation distribution in the column; for instance, the distribution represented by curve *B* of Fig 1. Such a distribution is unstable, and tends

to change so as to approach, ultimately, the stable, equilibrium distribution of curve A.

The distribution represented by curve B must approach that of curve A through the relative motion of parts of the liquid body; and there are two fundamental laws that this motion must obey. In the first place, it must obey Darcy's law, which for present purposes may be expressed as follows:

$$v = \frac{k}{\mu}\rho g - \frac{k}{\mu}\frac{\partial p}{\partial z} \qquad [1]$$

where:

- v = the macroscopic fluid velocity in the z-direction (downward).
- k = the permeability of the medium to the fluid (a function of the fluid saturation).
- μ = the viscosity of the fluid.
- ρ = the density of the fluid.
- g = the acceleration of gravity.
- p = the pressure in the fluid.

Eq 1 has several implicit complications when applied to the present problem. The permeability, k, is a variable that depends on the fluid saturation, decreasing as the saturation decreases. The variation of this quantity is not, however, an unfamiliar one. The more confusing quantity in the present problem is the pressure, p, which seems to have two different types of variation, one in the partially saturated region of the column, and another in the 100 pct saturated region.

In the partially saturated region (above 7 units on curve B of Fig 1) the fluid pressure is a function of the saturation, decreasing as the saturation decreases. If the part of pore spaces not filled by liquid is considered filled with gas having a negligible vertical pressure gradient, the pressure gradient in the liquid is a function of the saturation gradient only. This is in accordance with familiar laws of capillary behavior.[8,10]

In the 100 pct saturated region, there is, by definition, no saturation gradient, and, therefore, no pressure gradient because of that factor. Neither is there any externally applied pressure gradient, for if the column is open at the top and the bottom, and the gas surrounding the column has a negligible vertical pressure gradient, the externally applied pressure must be the same at the top and bottom of the column. In spite of these considerations, however, we know that there must be a pressure gradient in the 100 pct saturated region. This must be true because if it were not there could be no retention of that region after equilibrium had been reached. The pressure gradient in the completely saturated region of the equilibrium distribution must be calculable from Eq 1, by setting the velocity equal to zero:

$$v = \frac{k}{\mu}\left(\rho g - \frac{\partial p}{\partial z}\right) = 0 \qquad [2]$$

$$\therefore \frac{\partial p}{\partial z} = \rho g \qquad [3]$$

The pressure gradient given by Eq 3 must arise from the fact that at the upper boundary of the completely saturated region, the pressure in the liquid differs from the pressure in the gas. Experiments show that there is a definite interfacial curvature between the liquid and the gas at that boundary; and a pressure drop exists across the curved interface. The result is as if there were an applied negative pressure at the boundary. If the top of the 100 pct region of the equilibrium curve A of Fig 1 is at the height, H, it follows from Eq 3 that this negative pressure must be of the magnitude, $\rho g H$.

Now it seems reasonable to assume, at least as a working hypothesis, that in the nonequilibrium case, represented by curve B of Fig 1, a negative pressure equal to $\rho g H$ exists at the upper boundary of the 100 pct saturated region, where H still represents the equilibrium height of the top of the 100 pct region. In accordance with this assumption, the pressure gradient in the 100 pct region is:

$$\rho g \frac{H}{h} \qquad [4]$$

where:

H = the height of the top of the 100 pct saturated region after equilibrium has been reached.

h = the same, before equilibrium.

Eq 1 may now be written in two special forms, one for the incompletely saturated region, and one for the 100 pct saturated region. The equation for the upper region is:

$$v_u = \frac{k}{\mu}\rho g - \frac{k}{\mu}\frac{\partial p}{\partial z} = \frac{k}{\mu}\left(\rho g - \frac{dp}{d\xi}\cdot\frac{\partial \xi}{\partial z}\right) \qquad [5]$$

where:

u = a subscript denoting the unsaturated region.

ξ = the fractional saturation (the variable upon which the pressure, p, depends).

The equation for the lower region is:

$$v_s = \frac{k}{\mu}\left(\rho g - \rho g \frac{H}{h}\right) = \frac{k\rho g}{\mu}\left(1 - \frac{H}{h}\right) \qquad [6]$$

where:

s = a subscript denoting the saturated region.

Eq 5 and 6 are statements of Darcy's law in special forms for the present problem. Eq 5 must be combined with an equation of continuity in order to obtain an equation giving the time variation of the saturation in the upper region.

The equation of continuity may be written:

$$\frac{\partial v_u}{\partial z} = -\phi \frac{\partial \xi}{\partial t} \qquad [7]$$

where:

ϕ = the porosity, or per cent of space in the porous medium that could be occupied by fluids.

t = the time.

Eq 5 and 7 may be combined to give Eq 8:

$$\left[k\frac{dp}{d\xi}\right]\frac{\partial^2 \xi}{\partial z^2} + \left[k\frac{d^2 p}{d\xi^2} + \frac{dk}{d\xi}\cdot\frac{dp}{d\xi}\right]\left(\frac{\partial \xi}{\partial z}\right)^2 - \left[\rho g \frac{dk}{d\xi}\right]\frac{\partial \xi}{\partial z} = \mu\phi\frac{\partial \xi}{\partial t} \qquad [8]$$

The solution of Eq 8 would give the saturation history in the column of porous medium. Unfortunately, it is a complicated partial differential equation of the second order, whose solution by any method whatsoever would be exceedingly difficult.

Eq 8 may be simplified into a solvable form by neglecting the relatively unimportant terms. The terms involving capillary pressure gradients seem to warrant the first examination. The variation of capillary pressure with concentration is known to be small at intermediate and high saturations; and at low saturations where the variation is not small, the drainage process is possibly dominated by the low relative permeability of the liquid.

Laboratory determinations of capillary pressures at low saturations are of doubtful meaning because of the predominating effect of low permeabilities. Leverett,[11] for instance, has said that "the nearly vertical trend of the drainage data [the height-saturation relationship] at low water saturations represents a relatively poor approach to equilibrium, caused by the low permeability to water in this region."

Since the effects of capillary retention, and low permeability, are difficult to distinguish even in careful laboratory experiments, it seems overexacting to distinguish them rigorously in a practical theory. It is reasonable then to suppress the capillary pressure terms in Eq 8, with the provision that the joint effects of capillary retention and low permeability will be taken into account by an appropriate treatment of the terms involving the saturation-permeability relationship. For example, if in a porous medium, a liquid ceases to drain when a saturation of 10 pct is reached, large capillary pressure gradients may be responsible; but in calculations, the effect

may be taken into account by assuming that the permeability at saturations below 10 pct is zero.

On the basis of the above reasoning, the terms involving capillary pressure gradients may be omitted from Eq 8 to give Eq 9.

$$\frac{\partial \xi}{\partial t} = -\frac{\rho g}{\mu \phi}\frac{dk}{d\xi}\frac{\partial \xi}{\partial z} \qquad [9]$$

(Evidently, Eq 9 could be derived much more simply by neglecting the second, right hand term of Eq 1, before combining it with Eq 7. Eq 8 is developed completely, however, in order to show clearly why approximations are desirable.)

Eq 9 is solvable. Courant and Hilbert[12] discuss the solution of such quasilinear partial differential equations. The solution of Eq 9, which can be verified by differentiation, is:

$$\xi = \Phi\left(z - \frac{\rho g}{\mu \phi}\frac{dk}{d\xi}t\right) \qquad [10]$$

where Φ is an arbitrary function of the quantity in parentheses. The physical meaning of the arbitrary function, Φ, becomes evident if the time, t, is set equal to zero. One then obtains

$$\xi_{t=0} = \Phi(z) \qquad [11]$$

showing that Φ is the initial saturation versus height relationship. Eq 10 may be examined to find the height, z', at which a given saturation, ξ', will be found at any time. Since the quantity $dk/d\xi$ is itself a unique function of the saturation, fixing the saturation also fixes this derivative at, say, $f(\xi')$. Eq 10 may then be written:

$$\xi' = \Phi\left(z' - \frac{\rho g}{\mu \phi}f(\xi')t\right) \qquad [12]$$

where:

$$f(\xi) = \frac{dk}{d\xi}, \text{ a unique function of } \xi.$$

Now,

$$\xi' = \Phi(z'_{t=0}) \qquad [13]$$

If Φ is a single valued function of its argument, one may equate the parenthesized quantities of Eq 12 and 13 to obtain

$$z'_{t=0} = z' - \frac{\rho g}{\mu \phi}f(\xi')t$$

or

$$z' = z'_{t=0} + \frac{\rho g}{\mu \phi}f(\xi')t \qquad [14]$$

Eq 14 states that the downward distance at which a given saturation will be found varies linearly with time, and the rate of movement of the given saturation is proportional to the fluid density, the acceleration of gravity, and the derivative of the permeability to the liquid at that saturation. The distance is inversely proportional to the fluid viscosity and the porosity.

The most interesting aspect of Eq 14 is that it actually defines the form of the saturation versus height relationship in a column that was originally completely saturated, that is, in which

$$z'_{t=0} \cong 0 : 0 < \xi < 100 \qquad [15]$$

The form of the saturation versus height relationship in that case is given by Eq 16, in which the primes are now dropped:

$$z = \frac{\rho g}{\mu \phi}f(\xi)t \qquad [16]$$

or, if f^{-1} is the inverse of the function, f, the saturation itself is given by Eq 17:

$$\xi = f^{-1}\left(\frac{z\mu\phi}{\rho g t}\right) \qquad [17]$$

The movement of the upper boundary of the completely saturated region may now be investigated.

According to the theory already developed, the draining column consists of two regions. In the upper, unsaturated region, the fluid moves downward with a velocity given by Eq 5, with the capillary pressure term omitted:

$$v_u = \frac{k}{\mu}\rho g \qquad [18]$$

where k is a function of the saturation which itself obeys Eq 17. In the lower, completely saturated region, the fluid moves downward with a velocity given by Eq 6. The boundary between the two regions, which may be called the demarcator, must move with a velocity given by Eq 19:

$$\frac{dz_d}{dt} = \frac{v_s - v_{ud}}{\phi(1 - \xi_d)} \qquad [19]$$

where:

z_d = the position of the demarcator, the boundary between the unsaturated and saturated regions.

v_{ud} = the fluid velocity in the unsaturated region an infinitesimal distance above the demarcator.

ξ_d = the saturation an infinitesimal distance above the demarcator.

The saturation, ξ_d, is less than 100 pct in the present theory, although it is not less than 100 pct in actuality. A region of very rapidly decreasing saturation exists just above the demarcator. The neglect of this region is consistent with the suppression of terms involving small capillary pressure gradients, as discussed above.

The substitution of Eq 6 and 18 into Eq 19 gives:

$$\frac{dz_d}{dt} = \frac{\rho g}{\mu\phi} \frac{\left[k_1\left(1 - \frac{H}{h}\right) - k_d\right]}{(1 - \xi_d)} \qquad [20]$$

where:

k_1 = the permeability of the medium to the fluid at 100 pct saturation, $\xi = 1$.

k_d = the permeability at the saturation just above the demarcator (an infinitesimal distance).

Now if the draining column is of length, L,

$$h = L - z_d \qquad [21]$$

and Eq 20 will become:

$$\frac{dz_d}{dt} = \frac{\rho g}{\mu\phi} \frac{\left[k_1\left(1 - \frac{H}{L - z_d}\right) - k_d\right]}{(1 - \xi_d)} \qquad [22]$$

The integral of Eq 22 will give the position of the demarcator at any time. In order that it may be integrated, however, the variable permeability, k_d, and the variable saturation, ξ_d, must be expressed in terms of the dependent and independent variables, z_d, and t, using empirically determined relationships. The integration itself must, in general, be carried out numerically.

When the position of the demarcator at any time has been calculated, Eq 6 and 21 may be used to calculate the rate of drainage from the column; or Eq 17 may be used to calculate the saturation at all points from the top of the column to the demarcator, and thereby determine the total fluid that has drained from the column.

Empirical Data

Two empirical data must be used in the equations of the previous section: The permeability-saturation relationship, and the height, H, at which the top of the saturated region will stand when equilibrium is reached. The complete height-saturation (or capillary pressure versus saturation) relationship is not required in these approximate calculations.

When the empirical permeability-saturation relationship is used it must be in some simple mathematical form. Fortunately, there is a simple equation that fits published data[7,13] accurately:

$$k = k_1\xi^b \qquad [23$$

where:

k = the permeability at the saturation, ξ.

k_1 = the permeability at 100 pct saturation, $\xi = 1$.

b = an empirical constant.

The composite curve of Wycoff and Botset,[14] for instance, is fitted by the equation

$$k = k_1\xi^{3.5} \qquad [24]$$

where:

ξ = the saturation, expressed as a fraction (not in per cent). Eq 24 is suffi-

ciently representative to use in illustrative calculations.

Calculations

Assume, for simplicity, that a vertical column of unconsolidated sand is initially completely saturated with water, and then allowed to drain, both the top and the bottom of the column being open to the atmosphere. Assume that the physical constants of the system are as follows:

L, the column length	$= 200$ cm
k_1, the permeability at $\xi = 1$	$= 1$ darcy, or $9.9 \cdot 10^{-9}$ cm^2
H, the minimum height to which the water (at 100 pct saturation) will drain	$= 30$ cm
ρ, the density of the water	$= 1$ g per cm^3
g, the acceleration of gravity	$= 980$ cm per sec^2
μ, the viscosity of the water	$= 1$ centipoise, or 0.01 g per cm sec
ϕ, the porosity of the sand column	$= 0.30$
$\dfrac{\rho g k_1}{\mu\phi}$	$= 0.0032$ cm per sec

Eq 22 now becomes

$$\frac{dz_d}{dt} = 0.0032\,\frac{\left(1 - \dfrac{30}{200 - z_d}\right) - \xi_d^{3.5}}{(1 - \xi_d)} \qquad [25]$$

In order that Eq 25 may be integrated, the saturation, ξ_d, must be expressed in terms of the dependent variable, z_d, and the independent variable, t. This may be done by noting that the function, $f(\xi)$, used in Eq 12, and defined there as

$$f(\xi) = \frac{dk}{d\xi} \qquad [26]$$

can be derived explicitly from Eq 24.

$$f(\xi) = k_1 3.5\xi^{2.5} \qquad [27]$$

Then the saturation at any point in the unsaturated region, as expressed implicitly in Eq 17, may be expressed by Eq 29.

$$\xi = \left(\frac{\mu\phi z}{3.5\rho g k_1 t}\right)^{\frac{1}{2.5}} \qquad [28]$$

$$= \left(\frac{89z}{t}\right)^{0.4} \qquad [29]$$

In particular,

$$\xi_d = \left(\frac{89z_d}{t}\right)^{0.4} \qquad [30]$$

Combining Eq 25 and 30 gives:

$$\frac{dz_d}{dt} = 0.0032\,\frac{\left[\left(1 - \dfrac{30}{200 - z_d}\right) - \left(\dfrac{89z_d}{t}\right)^{1.4}\right]}{\left[1 - \left(\dfrac{89z_d}{t}\right)^{0.4}\right]} \qquad [31]$$

Eq 31 may be used in the form of an approximate difference equation such as Eq 32:

$$\Delta z_d = 0.0032\,\Delta t\,\frac{\left[\left(1 - \dfrac{30}{200 - z_d}\right) - \left(\dfrac{89z_d}{t}\right)^{1.4}\right]}{\left[1 - \left(\dfrac{89z_d}{t}\right)^{0.4}\right]} \qquad [32]$$

At any time, t, when z_d is known, t and z_d, may be put in Eq 32, and a new z_d at the time $t + \Delta t$ may be calculated. The continuation of this process amounts to a numerical integration of the differential Eq 31.

Unfortunately, the process described above may not be started at $t = 0$, for at that point the last terms of both numerator and denominator in Eq 32 are indeterminate. Special consideration must be given to the beginning of the numerical integration. One way of determining the initial behavior is to calculate the saturation at the very top of the column, an infinitesimal time after the drainage process has started. At the initial instant, and at small times

thereafter (when z_d is very small compared with 200):

$$\frac{d\xi_d}{dt} = \frac{\partial \xi_d}{\partial t} + \frac{\partial \xi_d}{\partial z_d} \cdot \frac{dz_d}{dt} \qquad [33]$$

$$\frac{d\xi_d}{dt} = \left(-\frac{0.4\xi_d}{t}\right) + \left(\frac{0.4\xi_d^{-1.5}89}{t}\right) 0.0032 \frac{\left[1 - \frac{30}{200} - \xi_d^{3.5}\right]}{[1 - \xi_d]} \qquad [34]$$

So that

$$\frac{d\xi_d}{-0.4\xi_d + 0.114^{-1.5} \frac{[0.85 - \xi_d^{3.5}]}{[1 - \xi_d]}} = \frac{dt}{t} \qquad [35]$$

Or,

$$\int_{\xi_1}^{\xi_2} \frac{d\xi_d}{-0.4\xi_d + 0.114\xi_d^{-1.5} \frac{[0.85 - \xi_d^{3.5}]}{[1 - \xi_d]}} = \int_{t_1}^{t_2} \frac{dt}{t} = \ln \frac{t_2}{t_1} + \text{constant} \qquad [36]$$

Now, as t_1 approaches zero, the right hand side of Eq 36 increases without limit; and this is true no matter what the value of t_2. It follows that the left hand side of Eq 36 must increase without limit as ξ_1 approaches the saturation corresponding to $t = 0$, no matter what the value of ξ_2. If the integrand is plotted, it is found that it has only one singularity that could give rise to an infinitely large value of the integral, and the saturation at this point is given by setting the denominator of the integrand equal to zero. That saturation here is 80 pct.

Although it has no direct bearing on subsequent calculations, it is interesting to note that the saturation calculated as indicated above is the saturation for which the downward velocity of the demarcator is a maximum.

This may be checked by differentiating Eq 31. The saturation in both cases is given by the general equation:

$$b\xi_d^{b-1} - (b - 1)\xi_d^{b} = 1 - \frac{H}{L} \qquad [37]$$

where:

b = the exponent in the permeability-saturation relationship,

$$k = k_1\xi^b$$

H = the equilibrium height of the top of the saturated region.

L = the length of the column.

If the downward velocity of the demarcator is maximized, it follows that the initial rate of drainage is also maximized. The instantaneous adjustment of the saturation at the top of the column, in order that this may occur, seems analogous to the familiar process in which water running down a hill chooses the steepest path.

Eq 32 may now be solved. Assume that the first time interval is 10 min., or 600 sec, and put the already calculated initial value of

$$\xi_d, \text{(initial)} = \left(\frac{89z_d}{t}\right)^{0.4} = 0.80 \qquad [38]$$

into Eq 32:

$$\Delta z_d \text{ (0 to 600 sec)} = 0.0032 \frac{\left[\left(1 - \frac{30}{200}\right) - (0.80)^{\frac{1.4}{0.4}}\right]}{[1 - 0.80]} 600 = 3.75 \text{ cm} \qquad [39]$$

Let the second time interval also be 10 min.:

$$\Delta z_d\text{(600 to 1200 sec)} = 0.0032 \frac{\left[\left(1 - \frac{30}{200 - 4}\right) - \left(\frac{89 \cdot 3.75}{600}\right)^{1.4}\right]}{\left[1 - \left(\frac{89 \cdot 3.75}{600}\right)^{0.4}\right]} 600 = 3.75 \text{ cm} \qquad [40]$$

So that

$$z_d\text{(1200 sec)} = 7.50 \text{ cm} \qquad [41]$$

This process may be continued, giving results like those shown in Fig 2.

The calculation of results like those shown in Fig 2 becomes difficult as the

position of the demarcator approaches its equilibrium height. The positive and negative terms in the bracketed part of the numerator of Eq 32 approach each other in absolute value, and small percentage variations in these terms cause large percentage variations in their difference.

When this difficulty is experienced, the calculations may be done with an approximation equation, such as Eq 42:

$$t \cong 89(170 - \epsilon)\left(\frac{30 + \epsilon}{\epsilon}\right)^{0.714} \quad [42]$$

where:

ϵ = the distance between the demarcator position and its ultimate position, equal to $L - H - z_d$.

This equation was derived by actually equating the two terms of the numerator of Eq 32. It is useful when those two terms are equal within a few per cent. It has not been rigorously proved that it is valid throughout the entire last part of the integration of Eq 32. Attempts at a rigorous proof failed.

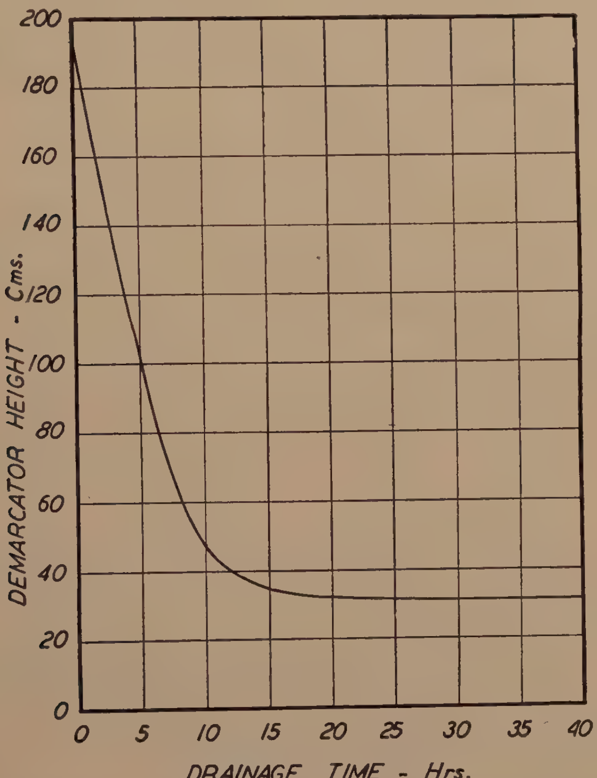

FIG 2—DEMARCATOR HEIGHT AT VARIOUS TIMES. EQUILIBRIUM DEMARCATOR HEIGHT EQUALS 30 CM.

Physical and mathematical indications are, however, that it is a reasonable assumption. As a check, the data for Fig 2, at large times, were calculated by using Eq 42, and also by a very laborious extension of the numerical integration. The check was good.

Fig 3 shows the saturation distribution in the column at various times. The heights of the top of the 100 pct region are those given in Fig 2. The saturation distributions in the unsaturated region are calculated from Eq 29.

As shown by the dotted line, capillary retention at low saturations can be imitated by assuming that the permeability is zero at saturations below 10 pct.

The assumption of zero permeability at saturations below 10 pct makes little practical difference in the saturation distribution except at infinite time. The empirical permeability-saturation relationship, Eq 24, alone, accounts for retention of the liquid in the column, throughout the significant part of the drainage period.

In the case illustrated in Fig 3, at 500,000 sec the drainage rate from the column has already dropped to 1 pct of the original rate, so the significant part of the drainage period may be said to be over.

It seems appropriate to discuss Fig 3 thoroughly, for the reason that its curves are different from those usually seen describing saturation distributions. The usual curves are of the general shape shown in Fig 1. The different shape shown in Fig 3 is due to the neglect of capillary pressure gradients arising from gradients in the saturation, as discussed previously. The shape in Fig 3 arises purely from the retardation of flow by diminished permeabilities due to diminished saturations. Although it is convex where it may seem that it should be concave, and its demarcator branch is impossibly horizontal, its general placement is essentially correct.

As a matter of practical fact, the curves of Fig 3 probably describe the saturation distributions in the drained column as

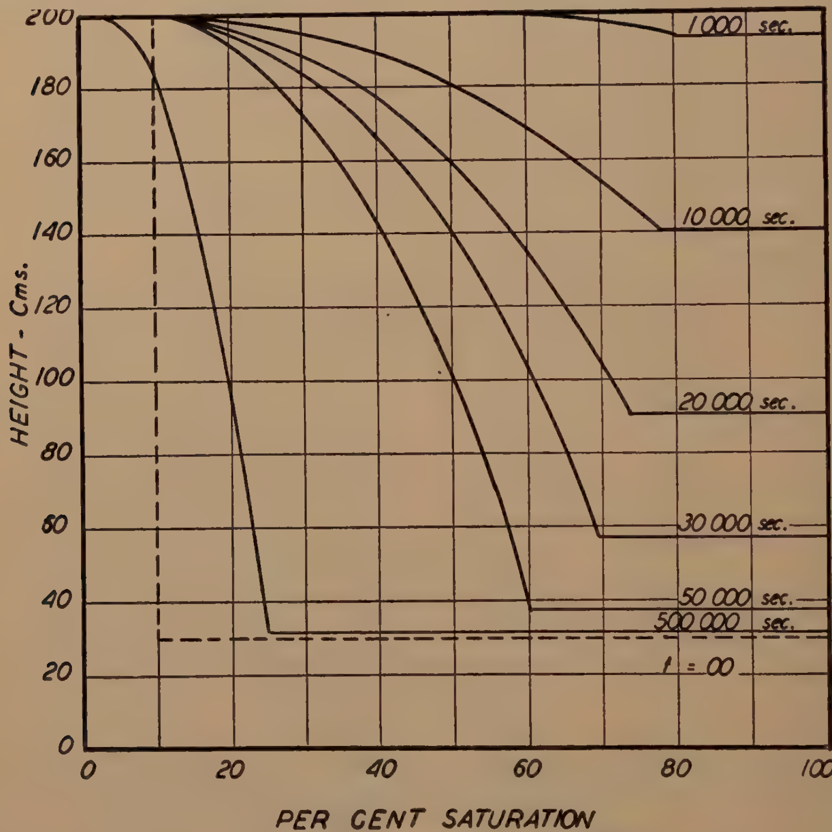

FIG 3—SATURATION OF COLUMN AT VARIOUS TIMES.

accurately as such distributions are ever determined experimentally, by current methods.

Fig 4 shows the percentage of the original liquid in the column that is drained out at various times. This liquid recovery is equal

Calculations to obtain information like that given in Fig 2 to 4 require 3 or 4 hr.

A Check on the Theory

The data of Stahl, Martin, and Huntington[9] are the most suitable data in the litera-

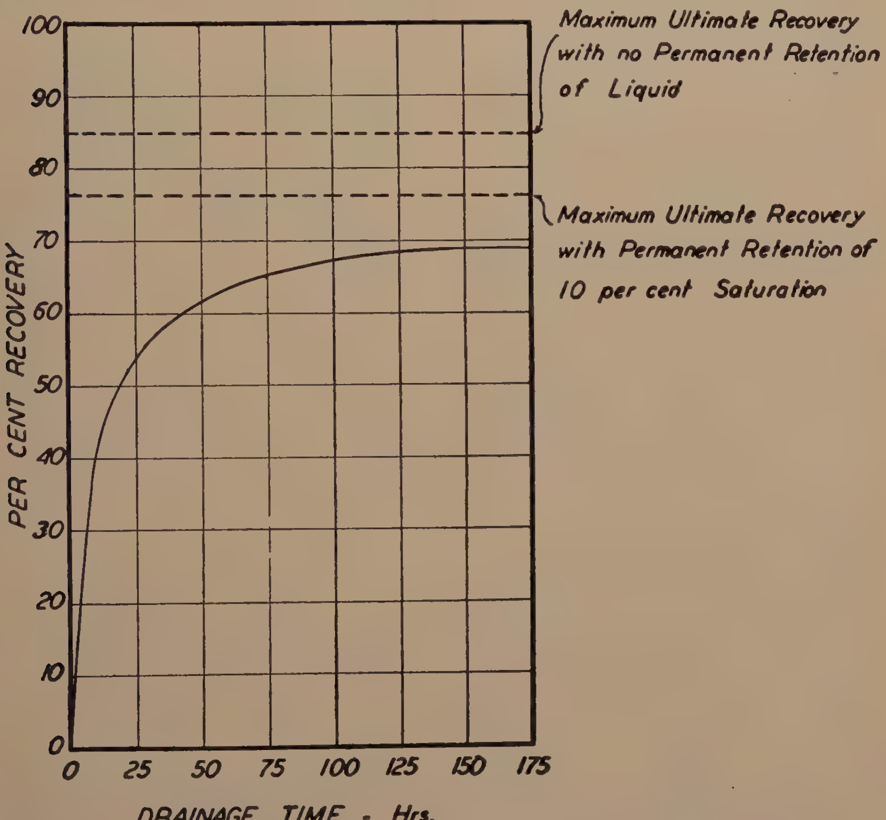

Fig 4—Percentage of liquid recovered by drainage from the column at various times.

to the percentage of the total area above the height versus saturation curve in Fig 3. Even at 500,000 sec, when the drainage rate has dropped to only 1 pct of its initial value, less than a half per cent difference exists in the calculated recovery depending on whether or not the permeability below 10 pct is set equal to zero. There is a difference of several per cent in the ultimate recovery, as shown in Fig 4, but this is not of practical significance.

ture with which to check the theory. We know of no other published drainage data obtained under such well-controlled conditions. For present purposes the data of Stahl and coworkers for Wilcox crude at 130°F are complete. The physical constants of this system are as follows:

L, the column length $= 244$ cm (8 ft)
k_1, the permeability at $\xi = 1$ $= 7.5$ darcys
$= 7.4 \cdot 10^{-8}$ cm^2
H, the minimum height

to which the water (at 100 pct saturation) will drain. This is an estimate based on the fact that the height at 56 hr is 15 cm = 10 cm

ρ, the density of the oil (calculated from the A.P.I. gravity at 60°F) = 0.81 g per cc

g, the acceleration of gravity = 980 cm per sec^2

μ, the viscosity of the oil (calculated from the kinematic viscosity, and the density) = 3.5 centipoises

ϕ, the porosity of the sand column = 0.32

If these data are treated in the same manner as the data of the illustrative calculation of the preceding section, the curve shown in Fig 5 is obtained. The experimentally determined recoveries, given by Stahl and coworkers,[15] plot satisfactorily on the calculated curve as shown in Fig 5.

Discussion of Results

The simple theory given in the preceding pages accounts for the variation of permeability in the unsaturated region at the top of a draining column. It does not account for capillary pressure gradients in this region. However, for unconsolidated sands having permeabilities of the order of a

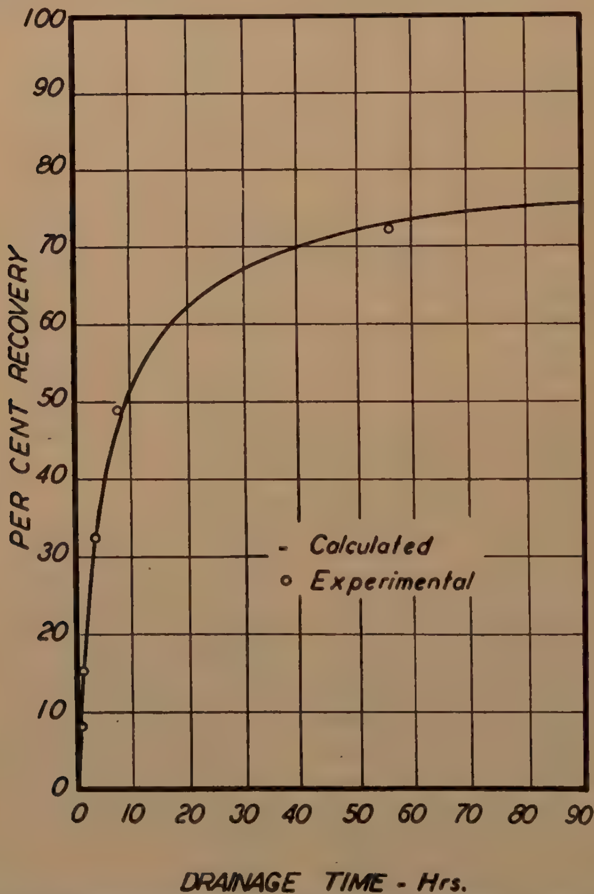

Fig 5—Comparison of experimental and calculated recovery by drainage. (*The* 130°F *Wilcox crude system of Stahl, Martin and Huntington.*[9])

darcy, this does not seem to be necessary. It may be concluded, therefore, that for all oil-bearing formations whose permeabilities are high enough to make gravity drainage important, the simple theory is adequate.

In order to make predictions of oil-field recoveries it will be necessary to modify the simple theory in many ways. Oil fields must usually be represented as only slightly inclined columns, rather than vertical columns. Account must also be taken of the convergence of flow into the draining wells. The effects of these factors may be approximated by known methods.

More difficult modifications will be necessary to account for the simultaneous action of other recovery mechanisms along with gravity drainage.

We hope that the simple theory presented here to account for the behavior of a vertical column will form a basis for experimental calculations of oil-field recoveries. We hope that it will be modified, improved, and expanded during attempts to use it in actual recovery predictions.

Acknowledgment

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DISCUSSION

Morris Muskat*—The authors are to be commended for undertaking the study of one of the most difficult outstanding theoretical problems in multiphase fluid flow through porous media. They have made an excellent start in outlining the mathematical problem involved in quantitatively describing the phenomena of gravity drainage and in demonstrating the types of solutions implied by the theory under simplified conditions.

There are several points related to the treatment of the paper which would merit clarification by the authors. The first relates to the basic simplification of dropping the capillary pressure terms in Eq 8 so as to lead to the simplified form of Eq 9. The fact that the former is virtually intractable analytically cannot be denied. But it is not clear that the terms neglected are actually of minor importance.

Simple estimates of the ratio of capillary pressure gradient forces to those due to gravity indicate that the two may be of the same order of magnitude even in intermediate saturation ranges. And a check on the magnitude of the terms dropped from Eq 8, using the solution of the simplified equation as given in Fig 3, indicates again that at least in the lower saturation range the neglected terms due to capillary forces will be comparable to, or even exceed, those due to gravity. It is true that the fixing of the ultimate retention limit, which is due to capillary forces, can be simply expressed by a vanishing permeability. It is not obvious, however, that the correctness of the dynamical details of the transition zone history would be thereby ensured.

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It may be of interest to note that the embarrassing discrepancy between the shapes of the curves of Fig 3 and those which are generally observed, such as reproduced in Fig 1, could be removed if the exponent b in Eq 23 were taken to lie between 1 and 2. If b lies in this range, the saturation curves of Fig 3 would become concave and simulate those of Fig 1 more closely. However, it is of course possible that if the generalized Eq 8 could be solved the curves would be concave even for higher values of b.

Another point needing some clarification relates to the basic significance of the solutions for still lower ranges in value of b which could conceivably be used to approximate curves of empirical relative permeability. Thus, if the permeability saturation curve were taken as linear, as might occur over appreciable saturation ranges, and the initial saturation were uniform, interpretation of the simplified solution as given by Eq 16 becomes obscure. It would seem surprising that the physical significance of the solution should depend so critically on the analytic structure of the permeability-saturation function. Indeed, if the function $f(\xi)$ is not monotonic, Eq 16 will give multiple values for the saturation distribution, and a corresponding physical ambiguity. While a non-monotonic character of $f(\xi)$ might appear anomalous from physical considerations, such is, in fact, suggested by Botset's experimental data on consolidated sand.

To the extent that the quantitative details of the wetting phase distribution in the unsaturated region are uncertain the integrated resultant curves of the recovery versus time, as plotted in Fig 4, will likewise be subject to some error. There may be some doubt, therefore, as to the significance of the agreement of theory with experiment as indicated in Fig 5. Perhaps an order of magnitude estimate of the cumulative rate of drainage might suffice in which the outflow velocity, as given by Eq 6, could be equated to a rate of fall in the height, h, adjusted by an approximate average drainage-recovery factor. In this connection it is to be observed that, as the authors indicate, Eq 6 itself represents an approximation assumption. If there is fluid movement in the saturated zone the pressure gradient will not be strictly the hydrostatic value given by Eq 3 or 4. Moreover, if the bottom of the column is literally free and open, there will be a capillary pressure discontinuity at the bottom, which may modify even the static internal pressure gradient from that given in Eq 4.

While it is realized that the problem is difficult enough when treating the drainage of a wetting phase, it would be of interest if the authors would indicate the possible modifications which might arise in the physical results when considering the drainage of a non-wetting phase as occurs in actual oil-producing systems.

Again it is to be emphasized that the problem is evidently extremely complex, and the authors have made an important contribution in crystallizing the problem and developing the solutions which at present appear the only type which can be expressed in a closed analytic from.

W. T. Cardwell, Jr. and R. L. Parsons (authors' reply)—Dr. Muskat has gone to the heart of the subject. It is therefore desirable to answer each of his points as completely as is possible at the present time.

Dr. Muskat's first point is that the capillary pressure terms of Eq 8 may not be truly negligible even for the cases that have been treated. The final answer to this comment is unknown. It is true that calculations of capillary pressure gradients that would exist in regions defined by the curves of Fig 3 give values that are not negligible. Indeed, Dr. Muskat has not emphasized the most questionable regions, where according to the curves, the capillary pressure gradients would be infinite. Such observations do not, however, constitute a rigorous disproof of the approximate validity of the solution that is graphed in Fig 3. The fact that it is an approximation has been explicitly stated in the paper. The degree of approximation is not known. Nor is it deducible simply from calculations of the type that have been made. Presumably, a rigorous estimate of the degree of approximation of the given simplified solution must await the solution of a more complete form of the gravity drainage equation.

Dr. Muskat's second point is that "the embarrassing discrepancy between the shapes of the curves of Fig 3 and those which are generally observed, . . . could be removed if the exponent b in Eq 23 were taken to lie

between 1 and 2." In the first place, it seems desirable to deny that the mentioned discrepancy is "embarrassing." It was discussed quite deliberately in the paper, where it was ascribed to the neglect of capillary pressure gradients. The shape of the curves of Fig 3 is the exact shape that would arise if only gravity forces were present, and if the retardation of drainage were due only to diminishing permeabilities, whose diminution was in turn due to diminishing saturations.

The suggestion that a sufficiently downward adjustment in the value of the exponent b would produce upward concavity is interesting. It provides a clue to a mathematical method of refining the low saturation end of the curve. At the present time however there seem to be no physical data upon the basis of which significantly lower values of b could be chosen for the entire permeability-saturation curve. It seems more reasonable to believe in the possibility mentioned by Dr. Muskat, that "if the generalized Eq 8 could be solved, the [drainage] curves would be concave even for higher values of b."

Dr. Muskat's third point concerns "the basic significance of the solutions for still lower ranges in value of b which could conceivably be used to approximate empirical relative permeability curves." He mentions first the possibility of a linear permeability-saturation relationship, and an initially uniform saturation and states that with these conditions the "interpretation of the simplified solution as given by Eq 16 becomes obscure." There is a difficulty here, but it can be resolved.

In the first place, no matter what the permeability-saturation function, the assumption of an absolutely uniform initial saturation leads to a trivial case of gravity drainage. Inside the region where the saturation is strictly uniform, the fluid velocity must be everywhere the same, and there is no tendency for saturation change due to gravity-produced movement. If the region is not continuously fed from the top, however, it must have an upper boundary that is moving downward. But if that boundary is assumed to be infinitely sharp, a true saturation gradient does not exist, and the differential Eq 9 (see p. 203) has no application. The problem becomes trivial. The infinitely sharp boundary merely moves downward with the same velocity as the fluid in the region below it.

Differential Eq 9 describes changes in saturation gradients that already exist, but it has no possible application when they do not exist, for its terms do not exist.

In the absence of capillary forces, gravity forces alone would not produce saturation gradients where they did not exist initially.

If any saturation gradient whatsoever is assumed to exist initially at the upper boundary of an otherwise uniformly saturated region, Eq 16 will properly describe the progressive changes in the shape of that boundary, and the interpretation of Eq 16 will lose the obscurity mentioned by Dr. Muskat. In the paper itself, the approximation sign in Eq. 15 (see p. 203), implies a condition in which there is such an initial height-saturation gradient as mentioned here. It is hoped that this more complete discussion will clarify the context of that equation.

Dr. Muskat next states that if the derivative of the permeability-saturation function is not monotonic, "Eq 16 will give multiple values for the saturation distribution, and a corresponding physical ambiguity." This is true. Eq 16, alone, does not handle this contingency, nor does the more general Eq 10 handle it alone. But this is by no means an indication that either of these equations is invalid under the conditions considered in the paper. It was not necessary to consider such contingencies there. What happens with a non-monotonic permeability-saturation derivative is more involved mathematically than anything that was discussed in the paper.

A restriction must be placed on the solution of Eq 9, to the effect that the height-saturation derivative must always be greater than zero.

$$\frac{\partial z}{\partial \xi} = \frac{1}{\frac{\partial \xi}{\partial z}} > 0$$

This restriction is necessary, because a zero derivative has no physical meaning. In the mathematical solution, the restriction prevents the derivative from instantaneously passing through zero to become negative, a process which is physically absurd.

Instead of the statement that the height-saturation derivative cannot become zero, a statement could be made that if it does become

zero in a region, the height-saturation curve simply ceases to exist there, and the differential Eq 9 ceases to control the behavior. Both statements amount to the same thing. The

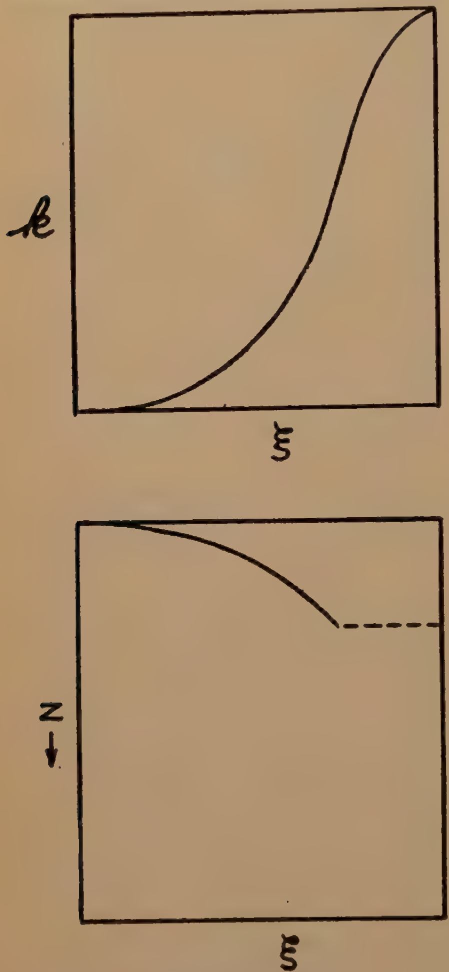

FIG 6—PERMEABILITY-SATURATION RELATIONSHIP HAVING A NON-MONOTONIC DERIVATIVE, AND THE TYPE OF NONEQUILIBRIUM DRAINAGE CURVE THAT IT WOULD CAUSE.

result is a discontinuity in the height-saturation curve representing the solution.

Fig 6 shows a schematic permeability-saturation curve whose derivative is non-monotonic, and the type of discontinuous height-saturation curve that would result during the drainage of a column having such a permeability-saturation curve. The discontinuity means that at a certain height in the column the height-saturation curve ceases to exist and at all points below that height the saturation is 100 pct. The discontinuity is like the demarcator already considered in the paper, but it arises from a different cause.

It can be proved that if the height-saturation curve is nearly horizontal at the beginning of drainage, the discontinuity will occur first at the saturation at which the second derivative of the permeability-saturation curve is zero. As the drainage progresses the discontinuity saturation will decrease. The equations are not given here. They are not hard to write, using the idea of the restriction, in conjunction with equations of the paper. Eq 16 of the paper is still applicable in the continuous region.

The above considerations should eliminate Dr. Muskat's doubts that the simplified gravity drainage equation can be solved so as to take into account various permeability-saturation relationships that might be encountered.

Dr. Muskat next states that "to the extent that the quantitative details of the wetting phase distribution in the unsaturated region are uncertain, the integrated resultant curves of recovery versus time, as plotted in Fig 4, will likewise be subject to some error. There may be some doubt, therefore, as to the significance of the agreement of theory with experiment as indicated in Fig 5." If the first sentence of this statement had said "*may* be subject to some error," it would be impossible to take issue with it. But there can be no certainty about the matter until it has been rigorously proved that the degree of approximation of the height-saturation curves must be reflected in the degree of approximation of the recovery curves. Intuitively, of course, this seems reasonable, but it is also possible to conjecture in the other direction.

The recovery is not a function of the shape of the height-saturation curve, but of the area bounded by it. Perhaps the capillary pressure terms alter the shape without altering the bounded area in a comparable degree. Support for this conjecture is given by an inspection of the complete gravity drainage Eq. 8 (see p. 202).

The only term on the left hand side of the equation that explicitly contains the density-gravity product, which product must control the recovery rate, is the term that has been

preserved in the solved Eq 9. Perhaps it can even be proved that the effect of the other terms on the recovery rate is negligible. At least, in the absence of proof, it is impossible to be certain otherwise.

As to the agreement of theory and experiment in Fig 5, it seems unreasonable to relegate it to the realm of coincidence.

Dr. Muskat's remaining mathematical comments as to the approximate bases of Eq 3, 4, and 6, emphasize points, which as he states, were indicated in the paper. They are well taken, and since it is not implied that they are of major importance, they perhaps require no discussion.

Dr. Muskat finally mentions that it would be of interest to indicate the possible modifications which might arise when considering the drainage of a non-wetting phase such as occurs in actual oil producing systems. It is not possible to answer this completely. For engineering calculations, however, until something more exact is developed, it is within reason to consider the wetting phase fictitiously as part of the rock, and to adjust the porosity accordingly. This gives reasonable results.

Dr. Muskat's comments have been penetrating and stimulating. The comments and the answers to them should clarify several phases of the subject that were not treated in the paper. They certainly indicate that the solution of even a simple gravity drainage problem has many complicated ramifications. It is hoped that the theory will have lasting value in both laboratory and field use. If it does nothing more, however, than incite others to examine the conditions of its validity by means of solutions of more complete equations, it will have served a gratifying purpose.

The Theory of Potentiometric Models

By Morris Muskat,* Member AIME

Abstract

The detailed analogy between flow systems in porous media and the corresponding potentiometric model systems is developed under conditions where it may be desirable to take into account variable pay thickness, variable porosity, and permeability, and also the dependence of the fluid density on pressure. It is shown that in such models it is only necessary that the electrolyte thickness be made everywhere proportional to the millidarcy-feet of the formation. In contrast to the iso-vol type model, previously suggested as a basis for the analogy, the porosity does not enter directly in the construction of the model. It is introduced only in translating the electrical voltage gradient measurements into the equivalent fluid travel times. A discussion of this procedure is given.

Introduction

It is now some 50 years since it was pointed out[1] that on the basis of Darcy's law Laplace's equation must govern the steady state flow of homogeneous fluids through porous media. It is 16 years since the obvious implication of this fact, namely, that such steady state homogeneous flow systems in porous media could be simulated by electrical analogies, was first applied[2] to problems of practical interest with respect to oil production. In these initial studies major emphasis was placed on the use of electrolytic models, made of blotting paper, to give a direct and graphic history of the fluid particle motion in regular and infinite well networks. However, it was also noted there that the basic requirement of the model was that it give a potential distribution similar to the pressure distribution in the flow system, and that from the electrical measurement of the potential distribution the fluid particle motion could be graphically or numerically determined. This was demonstrated by application to the five-spot infinite network, for which a conducting metallic sheet was used to establish the equipotential contours. As anticipated, the fluid particle motion computed from these contours agreed well with that given directly by the blotting paper model.

For irregular well distributions it was found more convenient to use electrolytic bath analogs rather than metallic sheets. Several investigations,[3,4] as applied specifically to cycling well patterns, have been reported with these models, which have become known as "potentiometric models." However, the extremely laborious nature of both the electrical measurements by direct probing and the associated interpretive computations retarded the widespread use of these procedures. The electrical measurements can be accelerated by using a four-probe electrode,[5,6] which provides a means for simultaneously determining the streamline paths along which the fluid particles must move and the voltage gradients along these paths which are proportional to the fluid velocities. With the increasing frequency of discovery of condensate pools, as drilling depths are becoming greater, the applicability of the potentiometric model to production problems, and especially to the study of well patterns for cycling, has been given a fresh impetus.

Although the formal theory for determining the motion of fluid particles in porous

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[1] References are at the end of the paper.

media has been developed for some time, and the general nature of the analogy between electrical conduction and flow systems is widely recognized,[7] the details of the conditions which must be satisfied to ensure equivalence between potentiometric models and their corresponding flow systems have not been fully discussed. Such treatments as have been reported[3,8] have been basically limited to systems of uniform permeability. Since the use of the four-probe electrode in potentiometric models has made their application to actual cycling systems a practical procedure, it is pertinent to re-examine the theoretical foundation of this type of reservoir analysis. Such an examination appears especially appropriate since there are indications not only that the full potentialities of the model are not being used, but that moreover some of the applications which have been made are of questionable validity. In particular, the use of "iso-vol" types of model does not appear to be justified, although this is apparently becoming common practice.[9] It is the purpose of this paper to present a detailed discussion of these matters.

The Formal Analogy

The equations of continuity for steady state current flow in an electrolytic medium and fluid flow in a porous body are:

$$\nabla \cdot \bar{\imath} = \nabla \cdot \bar{v} = 0 \qquad [1]$$

where $\bar{\imath}$, $\bar{v}$ are the vector current density and mass flux, respectively. Since model studies are generally, as a matter of practical necessity, based on a two-dimensional idealization in both the electrical and porous media flow systems, Eq 1 may be rewritten, by virtue of Ohm's and Darcy's laws, as:

$$\nabla \cdot \sigma \nabla V = 0 = \nabla \cdot \frac{\gamma k h}{\mu} \nabla p \qquad [2]$$

where σ is the equivalent electrical conductivity, V is the voltage, γ is the fluid density, k is the effective permeability to the mobile phase, μ is its viscosity, h is the local effective pay thickness, and p is the pressure. As γ and μ are, in principle, functions only of the pressure, the second of Eq 2 can be formally simplified by introducing the potential* function Φ,

$$\Phi = \int \frac{\gamma}{\mu} dp \qquad [3]$$

to:

$$\nabla \cdot kh \nabla \Phi = 0 \qquad [4]$$

If there is areal geometrical similarity between the reservoir of interest and the model, and both have the same source and sink distributions, corresponding to the injection and producing wells, it follows from a comparison of Eq 2 and Eq 4 that the electrical model will have a voltage distribution identical, except for scale, with that for Φ, provided σ is made everywhere proportional to kh. The variability of σ is obtained by varying the depth h_e of the layer of electrolyte to the model so that:

$$\sigma = \sigma_o h_e = akh \qquad [5]$$

where σ_o is the specific conductivity of the electrolyte, and a is a scale factor. That is, by satisfying the requirements of gross geometrical similarity and a variation of the electrolyte layer thickness in proportion to the millidarcy-feet of the formation the formal equivalence between the voltage and Φ distributions will be ensured.

As noted previously, it has been commonly assumed before that the electrolyte layer thickness variations in the potentiometric model should correspond to those in the iso-vol distribution of the productive formation. The iso-vols represent contours of constant pore volume, presumably corrected for the connate water saturation, so that the criterion equivalent to Eq 5 would be:

$$\sigma = a' f h$$

where f is the total or effective net hydro-

* Although Φ is not a potential function in a strict sense, this designation will be used here for convenience.

carbon porosity. However, it will be seen from the above considerations that the porosity does not enter at all in the construction of the correct electrolytic model analog, although, of course, when both the net porosity and permeability are considered as uniform, the electrolytic bath in either case—Eq 5 or the iso-vol model—would be made geometrically similar to an isopach map of the formation. The primary criterion for equivalence between the model and the actual reservoir is the creation of geometrically similar *potential* fields, which are determined only by the thickness, permeability and boundary conditions. The basic function of the model is to give an empirically measurable solution of Eq 2 for the pressure distribution. The determination of injection fluid fronts is essentially nothing more than an interpretation of this pressure distribution, as can be obtained by suitable numerical, graphical, or electrical manipulation of its characteristics, and as will be discussed later.

It is also significant to observe that the iso-vol type of model, while fundamentally incorrect, also fails to provide directly for a possible permeability variation. Such variations apparently are introduced in the iso-vol models only in the calculation of the fluid front contours from the measured potential distribution, although even this is seldom done in practice. A model based on Eq 5 brings into play the permeability directly in the construction of the model. It is the porosity which modifies independently the actual fluid motion when translating the potential distribution into particle velocities; but the permeability, if variable, also enters then as a factor as will be seen in the next section.

While no such justification has been indicated in the literature, it is true that for certain systems of simple geometry where only the porosity is variable, the same result pertaining to the fluid particle motion will be obtained whether an iso-vol model is used or one based on Eq 5. If, however, the permeability is variable, whether or not the porosity is constant, erroneous results will be obtained even in these simple systems, if the permeability is introduced as a modifying factor when using an iso-vol model. And if it is not so introduced, the iso-vol model loses completely all potentialities of even approximately handling variable permeability problems. Moreover, in systems of general and complex geometry the accidental validity of the iso-vol model breaks down in variable porosity formations even if the permeability is uniform, since no general relationship will obtain between the potential distributions in the iso-vol model and one based on Eq 5. In fact, even the basic geometry of the equipotential and streamline distributions will in general be radically different.

THE FLUID FRONT CONTOURS

In view of the construction of the potentiometric model according to the requirements of Eq 5, special consideration must be given to the interpretation of the measured potential distribution which will correctly give the injection fluid front contours. To derive the character of the fluid motion it is noted that the rate of local fluid advance along the streamlines will be given by:

$$\frac{ds}{dt} = \frac{v}{\bar{f}} = \frac{k}{\mu\bar{f}} \nabla p = \frac{k}{\bar{f}\gamma} \nabla \Phi \qquad [6]$$

where v is the local volumetric flux along the streamline, and $\bar{f}$ is the displacement porosity, that is, the actual porosity times the fraction of the pore space displaced by the invading fluid.* It will be observed that it is in the computation of the rate of fluid front advance where the porosity enters the problem, and even this occurs only in trans-

* It is intuitively probable, and it has been essentially confirmed experimentally, that in cycling operations there is no appreciable mixing between the injected dry and displaced wet gas. Under such conditions $\bar{f}$ is the total hydrocarbon porosity.

lating volumetric fluxes to linear velocities. The functions p and Φ are entirely independent of the porosity, excepting only as the latter is indirectly and perhaps accidently related to the permeability. The time of travel over an element of length ds along a streamline will therefore be:

$$dt = \frac{\bar{f}\gamma\, ds}{k\nabla\Phi} \quad [7]$$

Hence, if the potential distribution represented by Φ is known, Eq 7 will permit the stepwise integration of the time of advance of the fluid front. To carry through this procedure with the aid of the voltage distribution in the potentiometric model, the scale factors, L, M may be introduced as:

$$\begin{aligned} ds_M &= L\, ds_R \\ V &= M\Phi \end{aligned} \quad [8]$$

where ds_M is a linear distance in the model and ds_R the corresponding distance in the reservoir, and M is, in effect, the ratio of the total voltage between two points in the model to the corresponding difference in Φ in the reservoir. It then follows that Eq 7 can be rewritten as:

$$dt = \frac{M}{L^2}\frac{\gamma\bar{f}}{k}\frac{ds_M}{\nabla V} \quad [9]$$

If, as in the use of the four-probe electrodes, the potential drop ΔV is measured along the streamlines over the fixed electrode separation Δs_m, the corresponding fluid travel time increments will be:

$$\Delta t = \frac{M\Delta s_m^2}{L^2} \cdot \frac{\gamma\bar{f}}{k} \cdot \frac{1}{\Delta V} \quad [10]$$

By summing such increments along the individual streamlines the constant time surfaces can be plotted. These evidently correspond to the various fluid injection fronts, or interfaces between the injection and displaced fluids.*

* It is assumed here, as throughout all electrical model applications, that there are no significant differences in the dynamic or other properties between the injection and displaced fluids.

It is to be noted that if the coefficient $\frac{\gamma\bar{f}}{k}$ is variable, the sum of the reciprocals of ΔV will not alone suffice to determine quantitatively the shapes of the injection fluid fronts. On the other hand, in most practical applications it will be necessary to make such approximations as will permit simplifications of Eq 10. Thus, if permeability variations are neglected, the value of k can be combined with the constant factor $M\Delta s_m^2/L^2$. If $\bar{f}$ is also considered as constant, the only remaining variable in Eq 11, except for ΔV, will be γ. Since γ does not vary rapidly in cycling systems except near the injection and producing wells, it may suffice to neglect its variation outside of these regions, if average values are used, in actual field studies. In fact, such approximations would appear to be inherently reasonable if the variations in $\bar{f}$ and k are also neglected.

As indicated by Eq 6, the velocity of advance of the fluid front will be proportional to the pressure gradient whether the fluids involved are gases or liquids. The pressure distributions, however, will be quite different in the two cases. On the other hand, since the distributions in the function Φ will be the same for gases and liquids for a given reservoir formation, the shapes of the injection fluid fronts will be different for gases only because of the factor γ in Eq 7. The assumed equivalence in these fronts for liquid and gas systems thus implies the neglect of the variation of the gas density γ.

Although the shapes of injection fluid fronts will be independent of the fluid viscosities, if constant, the absolute times of travel will be essentially proportional to the viscosity. Moreover, even aside from the effect of the viscosity, the sweep rates will be different for gas and liquids, for the same terminal pressures, because of density variations.

While the density factor in Eq 7 makes almost impossible a strict analytical treat-

ment of the motion of gas injection fluid fronts, even in uniform systems, it does not present unsurmountable difficulties when using the potentiometric model if it is felt desirable to take it into account. For it is only necessary that the density distribution be calculated from the potential distribution,* and its local value be multiplied into the reciprocals of the gradients, according to Eq 7 or Eq 10, to obtain the time increments. Such a stepwise evaluation of the latter would be required anyway if the permeability or displacement porosity is variable. Actually, however, even the effects of the latter are usually neglected in practical applications, and the travel times are determined simply by summing the reciprocals of the potential increments, ΔV. Moreover, from a practical standpoint attempts to take into account the lateral variations in permeability and displacement porosity will not be warranted unless they are known with some certainty. When these effects must be neglected of necessity, it is doubtful if the corrections due to the density variations would be justified except in the immediate vicinities of the individual wells.

From the above discussion it will be seen that, if properly constructed and used, the potentiometric model can be applied to determine accurately the nature of the fluid motion in continuous reservoirs with any type of variation, singly or in combination, of the net formation thickness, the effective permeability, and net hydrocarbon porosity. The only physical limitations are the assumptions of negligible cross-flow and the dynamic identity between the fluids on either side of the advancing interface of interest. This should be of little significance in the case of cycling systems. When deemed necessary or desirable, full account can be taken of the changing density of the gas phase associated with the pressure distribution, in a manner involving no more complications than required for taking into account permeability and porosity variations. When the latter are of importance and can be explicitly defined, the iso-vol type of model will give erroneous results, and will not reflect the true potential distribution controlling the fluid particle motion.

Finally, it should be emphasized that even when the potentiometric model is constructed and applied correctly, such quantitative deductions as may be drawn from it will be no more accurate than the reservoir data on which it is based. Precision confirmation of model predictions by field observations can hardly be little more than accidental coincidences. This must of necessity be so when gross approximations of strict reservoir uniformity in permeability and porosity are made. And even when account is taken of the best data available from coring and logging analyses, it is very doubtful that quantitatively accurate interpolations of the areal variations in permeability and porosity will be more than an extremely remote possibility. On the other hand, these considerations do not imply any serious limitation on the power of the potentiometric model analysis in discriminating between definitely inefficient and satisfactory cycling patterns. Nor will such predictions as are derived from it, when properly developed and combined with other pertinent reservoir information, be subject to serious question when used in determining the gross economic feasibility of cycling operations. Such uncertainty in the quantitative significance of potentiometric model studies as arises from the factors considered here is only one of a number involved in all types of reservoir analysis, and there is much evidence to prove that experienced study of all aspects of the composite problem will usually lead to evaluations providing a sound basis for economic and efficient reservoir development.

* Although the potential or pressure distribution usually is not explicitly determined when using the four-probe electrode, it can be readily calculated from the ΔV measurements.

Acknowledgment

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CHAPTER IV. *Research Engineering*

Lance Creek Sundance Reservoir Performance—a Unitized Pressure-maintenance Project

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(Denver and Tulsa Meetings, September–October 1947)

ABSTRACT

THE Lance Creek Sundance reservoir provides a case history of 10 years performance of a reservoir in which unit operation has permitted effective utilization of gravity drainage augmented by primary pressure control with injection of gas into top structural wells. Detailed performance of the reservoir is presented by means of maps of well status, reservoir pressure, individual well recovery, etc., and by pool-performance charts. Analysis of reservoir performance indicates only minor water encroachment, so that gravity, injected gas, and expansion of gas are the main oil-expulsive agents.

A simplified theory of regional drainage of oil from upstructure location to downstructure location due to gravity is presented and checked by means of comparison of "reservoir" permeability and "well" permeability from the pool performance. Good order of magnitude agreement was obtained.

Individual well performance and overall reservoir performance indicate possibility that maintenance of pressure makes ineffective those parts of the reservoir in which permeability is too low to permit effective drainage of oil by action of gravity. Oil from these parts can be recovered only when pressure is reduced locally by selective withdrawal or when overall reservoir pressure is finally reduced.

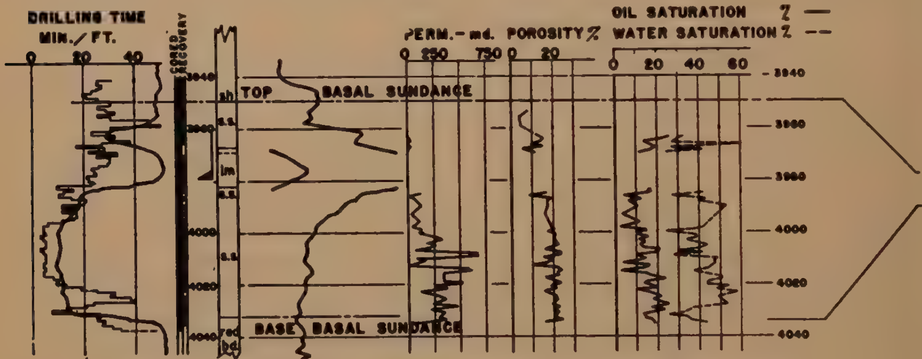

FIG 1—COLUMNAR SECTION AND COMPOSITE LOG, LANCE CREEK FIELD.

INTRODUCTION

The Lance Creek oil field, Townships 35 and 36N, Range 65W, Niobrara County, Wyoming, was discovered in October 1918, when Ohio Well No. State 1 was

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completed in the Dakota horizon at a depth of 3665 ft, with an initial production of 1500 bbl daily. Gradual development of this shallow horizon in a rather sporadic manner led to completion of some 90 wells by 1930. In addition, about 10 wells each had been completed in both the Muddy and Lakota sands.

However, soon after this a minor sand—

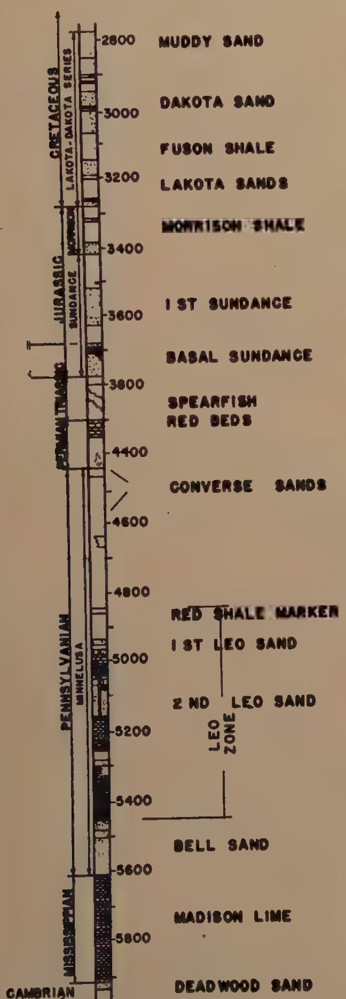

Fig 1—*Continued.*

the First Sundance—was found by the Ohio Oil Co. and the discovery well was completed with a 600-bbl daily yield of 40° oil. Four and one-half years later, deeper development of this pool led to discovery of the subject reservoir—the Basal Sundance—for 2000 bbl a day of 47.5° gravity oil in Well No. Agnes Rohlff 2, some 150 ft lower in section. The final and deepest pay was put on production in May 1937, when Ohio completed its first well in the prolific Leo reservoir (water drive) at a depth of 5538 ft for 1850 bbl daily.

Stratigraphy at Lance Creek is sketched on the columnar section, Fig 1, showing the relation of the Basal Sundance—a lower Jurassic member—to the other horizons. Depth range of the Sundance varies from 3200 to 4400 ft. The Sundance group, lying unconformably above the Triassic Spearfish red beds, includes the Basal series consisting of sandstone, black shale, laminated limestone, and siltstone according to the Unit geological committee. The committee also characterized the Lance Creek anticline as a curved elongated asymmetrical fold lying on the southeast flank of the Powder River Basin, separated from the Hartville uplift (to the southeast) by a low syncline. Reservoir closure is approximately 440 ft and, although several faults can be traced in the Sundance series, the Basal Sundance pools are not affected except by the fault responsible to some degree for the barrier that separates the sand into two pools, as shown in Fig 6. Depositional or sedimentary factors are also believed to be important in this separation (see isopach map, Fig 2). It may be noted that the outline of the Unit participating area follows this feature.

Early observation of well and reservoir behavior led the principal field operators—Ohio, Continental, and Argo oil companies—to investigate the possibilities of unitization in order to achieve maximum oil recovery. These efforts, assisted and encouraged by the U. S. Geological Survey and the Bureau of Mines, culminated in unitization of most of the main Basal

Sundance pool in January 1938, upon the basis of productive acreage.

Although individual operators continued to produce their leases and equalize lifting costs on a per-barrel basis, each well was controlled according to the Unit production plan established by the Operator's Committee and administered by the resident Unit Coordinator. Gas production, previously sold to a local carbon-black plant, was processed by a gasoline plant built and operated by Continental Oil Co.

Included in the plant were sufficient compression facilities to return available residue gas to the Unit Sundance pool through wells selected by the Operating Committee upon recommendation of the Engineering Subcommittee. Except for plant, field, and camp use, the only residue gas sold after unitization was to drilling wells in the neighborhood. Smaller quantities of gas were injected into the Leo pool during 1914 and 1942, with negligible amounts in subsequent years (a total of 3.2 billion cubic feet). The principal Buck Creek Sundance operator also injected moderate amounts of gas (see Fig 12) totaling 4 billion cubic feet as of July 1947.

Although the same operators subsequently unitized the Leo pool, as well as the minor Converse and First Sundance reservoir, the last two have not been repressured to date. In addition to the residue injection, the Unit Basal Sundance has received more than 25 million gallons of propane and butane conserved during seasons of slack demand. Occasionally surplus residue was stored in the shallower Dakota sand for future use, but the total is less than 3 billion cubic feet.

Reservoir Performance

Unit Area

Graphic records of reservoir behavior are furnished in Fig 3 and 4. Prior to 1938, and before unitization, estimates of annual production were the only values available but later reliable monthly records of oil, gas, and water production make reservoir calculations possible with fair engineering accuracy. Individual well-production gauges, tests, and histories, however, are not adequate to permit the complete analysis justified for such a valuable field.

Special well tests here and there, with overall study of the field, from every angle, supported by the invaluable personal assistance of the local engineers and supervisors, have helped greatly in fitting the picture together.

At any rate, study of the curves will reveal the stabilization of pressure effected by unitization and augmented by gas injection. The control of net gas-oil ratio is shown with its seasonal variation for a period of 9½ years. The decline and trend of oil production is also shown and, in relation to the number of producing wells, hints of the average well-production trend—although individual well curves are required to show the production as related to pressure areas, gas-oil ratios, and other controlling factors. It should be noted that the water production has been plotted on an enlarged scale on Fig 3 to show trends; it is considerably lower than oil production in magnitude.

Well status is shown early in unitized life by the map in Fig 5, and contemporary pressure distribution and productivity index on Fig 6. For the purpose of this paper wells have been numbered consecutively from west to east in each reservoir. Comparative well status and pressure maps are furnished for 1942 and 1947 (Fig 7–10). Study of these maps will disclose the spread of high gas-oil ratios, the incidence and trend of water production, distribution of gas injection, and reservoir-pressure pattern.

Correlation of the general pool behavior illustrated by the six maps just reviewed, with the cumulative oil-production maps shown in Fig 11, yields a panorama of the extent to which gas-oil segregation was achieved. Further study in connection with

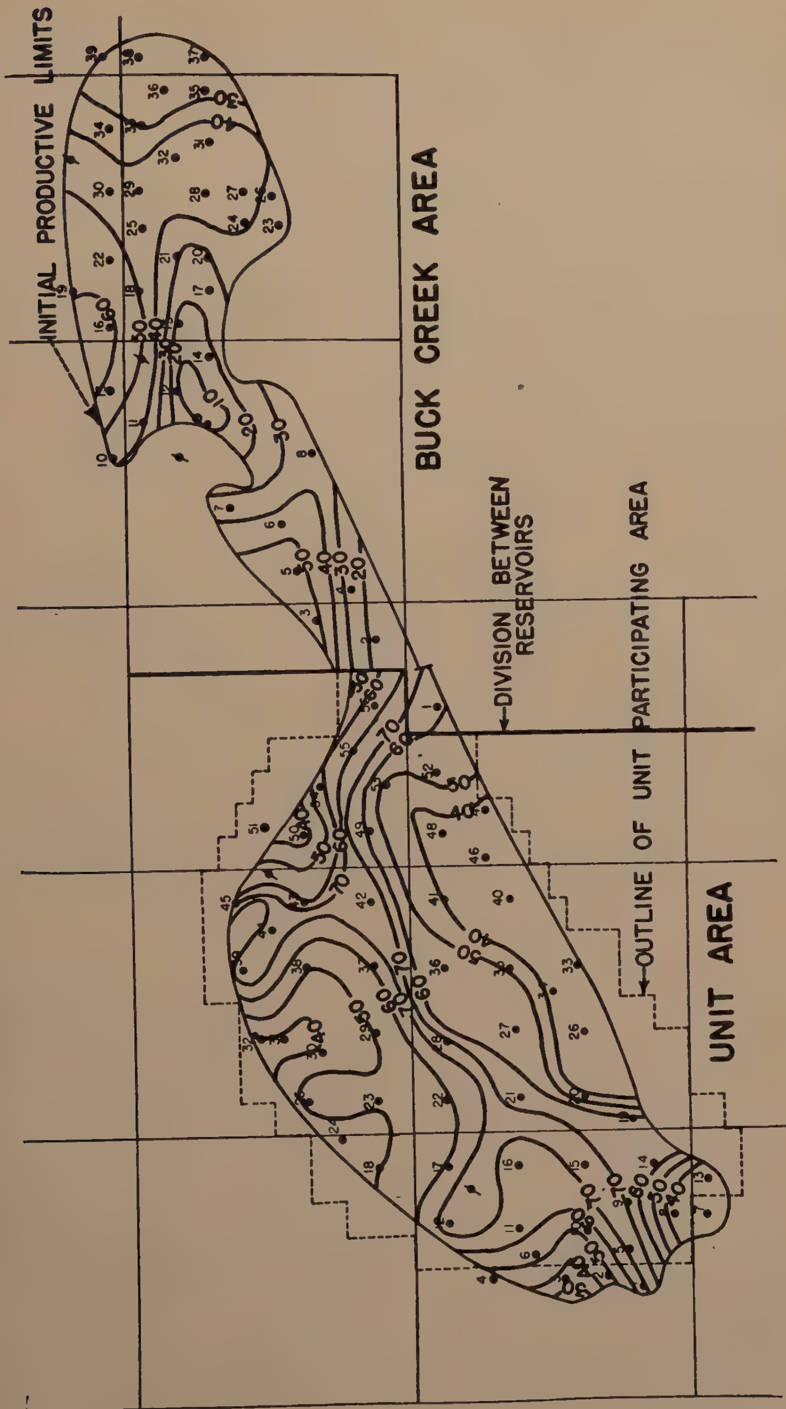

Fig 2—Isopach map, Lance Creek field.

the isopachous map, Fig 2, accentuates the general concentration of recoveries in lower wells despite variations in textural conditions and individual well handling, etc.—and even though most well figures oil rate, and relatively larger, but still unimportant, water production. Later mathematical analyses will treat these variations in connection with structural and lithological differences as well.

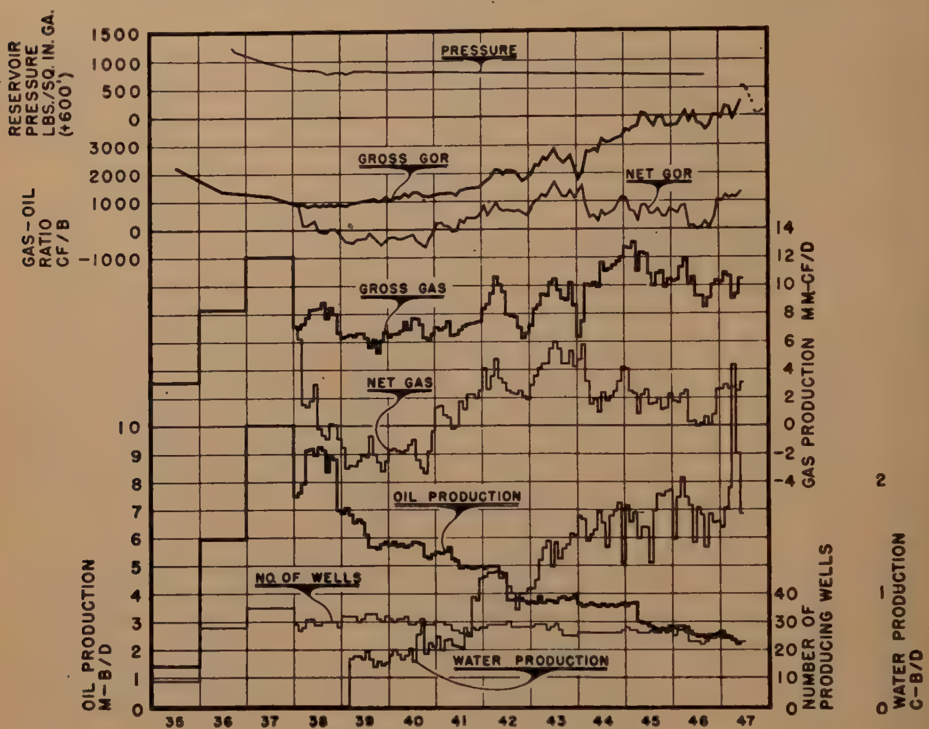

Fig 3—Performance curves, Unit area.

are estimates based upon occasional individual gauges.

Additional evidence of fairly effective gravity drainage and fluid segregation is provided by Table 1, showing cumulative recovery to date per acre-foot of pay by 100-ft contour sections of the reservoir.

Buck Creek Area

Similar curves (Fig 12 and 13), the same maps, and Table 2, present the picture of performance on the smaller reservoir. Its behavior was somewhat different from that of the Unit pool, particularly in regard to degree of pressure maintenance,

Analysis of Reservoir Performance

Unit Area Reservoir

The productive limits and net pay thickness of the Basal Sundance reservoir are outlined on the isopach map in Fig 2. Some 1450 acres were initially oil productive, and out of a total zone thickness ranging from 57 to 118 ft, the average net pay was about 52 ft based on electric logs, core analyses, and sample examinations. Wells drilled to the deeper Leo sand helped considerably in defining these limits, since the Leo production extends laterally beyond the Basal Sundance limits. Available core analyses indicate porosity ranging from 20 to 30 pct with an average of 25 pct and permeabilities

ranging up to 1250 md with an average of 260 md. Interstitial water saturation is estimated to have been 25 pct.

Possibility of a small initial gas cap or gas cap. If it be assumed that effective permeability to gas in the free-gas zone and effective permeability to oil in the underlying oil zone were equal, calculations

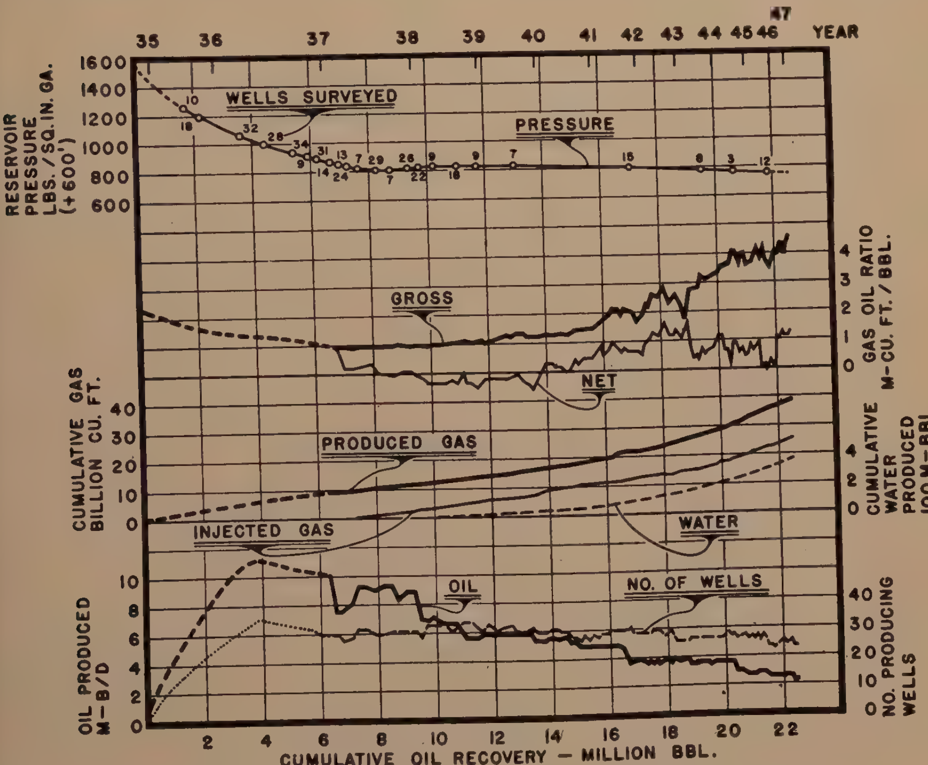

FIG 4—RESERVOIR PERFORMANCE VS CUMULATIVE RECOVERY, UNIT AREA.

stray free-gas zone at the top of the structure is indicated by initial gas-oil ratios of wells within the +600-ft contour level. The wells drilled within the first year of production had gas-oil ratios of 2500 to 3000 cu ft per barrel, while one well, drilled 1½ years after the discovery well, had a gas-oil ratio of 11,700. All but five wells, out of 19 drilled before 1937 outside the +600-ft contour had gas-oil ratios from 500 to 900 cu ft per bbl, and three of these five were completed after well datum pressures had declined to between 1075 and 1300 psi. All of these wells had substantial initial oil production and in no sense can these ratios be considered evidence of a major indicate that only about 10 pct of the net pay thickness contained free gas. Since the area within the +600-ft contour contains only about 20 pct of the total reservoir volume and the free-gas cap only a small part of that, the initial free-gas cap could have occupied but a small part of the total reservoir and has played a minor part in the performance of the reservoir.

Using these data, the initial effective sand volume is estimated to be 77,000 acre-feet and the initial tank oil content about 73 million barrels. The initial gas cap is estimated to have contained only a few billion cubic feet of free gas.

Neither the initial reservoir pressure nor

TABLE 1—*Recovery vs Structural Position, Unit Area*

Contour Interval, Ft	Acres	Acre-feet	Number Producing Wells	Cum. Oil Recovery to 7-1-47 M Bbl	Bbl per Acre	Bbl per Acre-foot	M Bbl per Well	Barrels per Day, June 1947
Above +600	262	15,500	8	545	2,080	35	68	0
+500 to +600	367	21,600	12	6,834	18,650	316	569	453
+400 to +500	492	24,700	22	9,881	20,100	400	449	1,166
Below +400	329	15,200	14	5,203	16,320	343	372	760
Total	1,450	77,000	56	22,463	15,500	291	400	2,379

initial saturation pressure of the reservoir oil was measured so none of the usual material or volumetric-balance methods of estimating initial oil content can be applied strictly. Nevertheless, the pressure-production performance can be combined with the volumetric estimate of oil content to determine general agreement between the two. Hydrostatic gradient from the surface elevation to the +600-ft datum would indicate an initial pressure of about 1650 psi. Correction to the Basal Sundance datum from the measured initial pressure of the deeper Leo sand in Lance Creek indicates about 1550 psi, and correction from the initial pressure of the Dakota sand in the nearby Little Buck Creek field would indicate about 1450 psi. Extrapolation of average Basal Sundance pressures versus cumulative production back to initial conditions, as shown in Fig 4, indicates some value between 1450 and 1550 psi to be reasonable. The highest measured individual well datum pressures were about 1300 psi in September 1936, 1½ years after the discovery well was drilled and after some 1.8 million barrels of oil had been produced.

Using the estimated gas production prior to commencement of gas injection, based on gasoline-plant volumes, gas sales to the carbon-black plant, and well tests, the initial average saturation pressure was calculated to about 1350 psi. The highest measured saturation pressure on a subsurface sample taken in June 1937 was 970 psi. Initial production tests of early wells indicate somewhat lower gas-oil ratios in the downstructure areas than in the intermediate and top structural locations. This suggests a condition of variable saturation pressure throughout the reservoir and thus reconciles existence of free gas at a pressure of 1450 to 1550 psi with a calculated saturation pressure of about 1350 psi. This is further borne out by the decreasing rate of decline in pressure with production prior to commencement of gas injection. Part of this decrease is due to lowering average gas-oil ratio by drilling of more wells in the downstructure low-gas-oil ratio area. During the period from September 1936 to July 1937, oil production was some 12,000 bbl per pound drop in pressure whereas oil and gas production (measured at mean reservoir pressure) was about 41,000 bbl

TABLE 2—*Recovery vs Structural Position, Buck Creek Area*

Contour Interval, Ft	Acres	Acre-feet	Number Producing Wells	Cum. Oil Recovery to 7-1-47, M Bbl	Bbl per Acre	Bbl per Acre-foot	M Bbl per Well	Barrels per Day, June 1947
Above +350	91	3,400	3	212	2,325	62	71	0
+250 to +350	522	20,100	23	4,686	8,980	233	204	1,453
+150 to +250	128	4,900	8	833	6,500	170	104	191
Below +150	119	3,100	5	978	8,220	315	195	331
Total	860	31,500	39	6,709	7,810	213	172	1,975

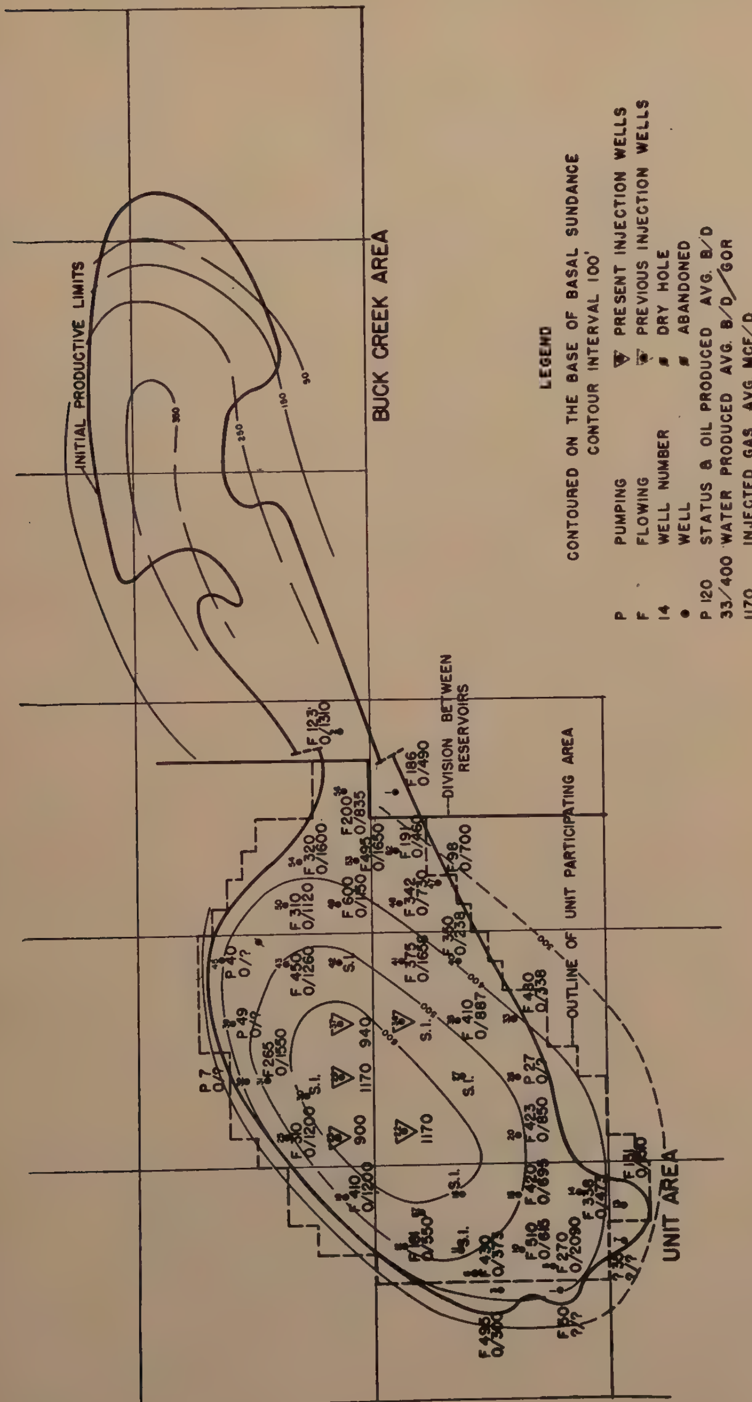

FIG 5—WELL STATUS, LANCE CREEK FIELD, JUNE 1938.

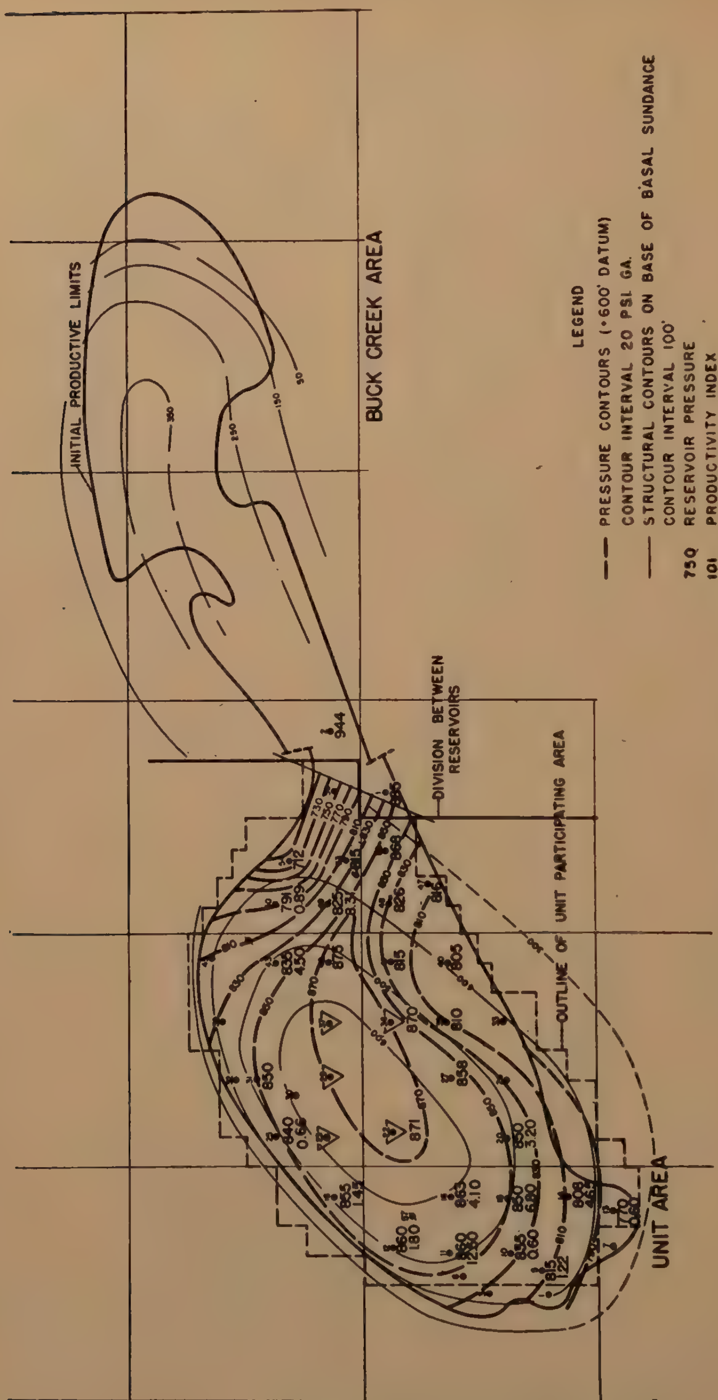

Fig 6—Reservoir pressure, Lance Creek field, April 1938.

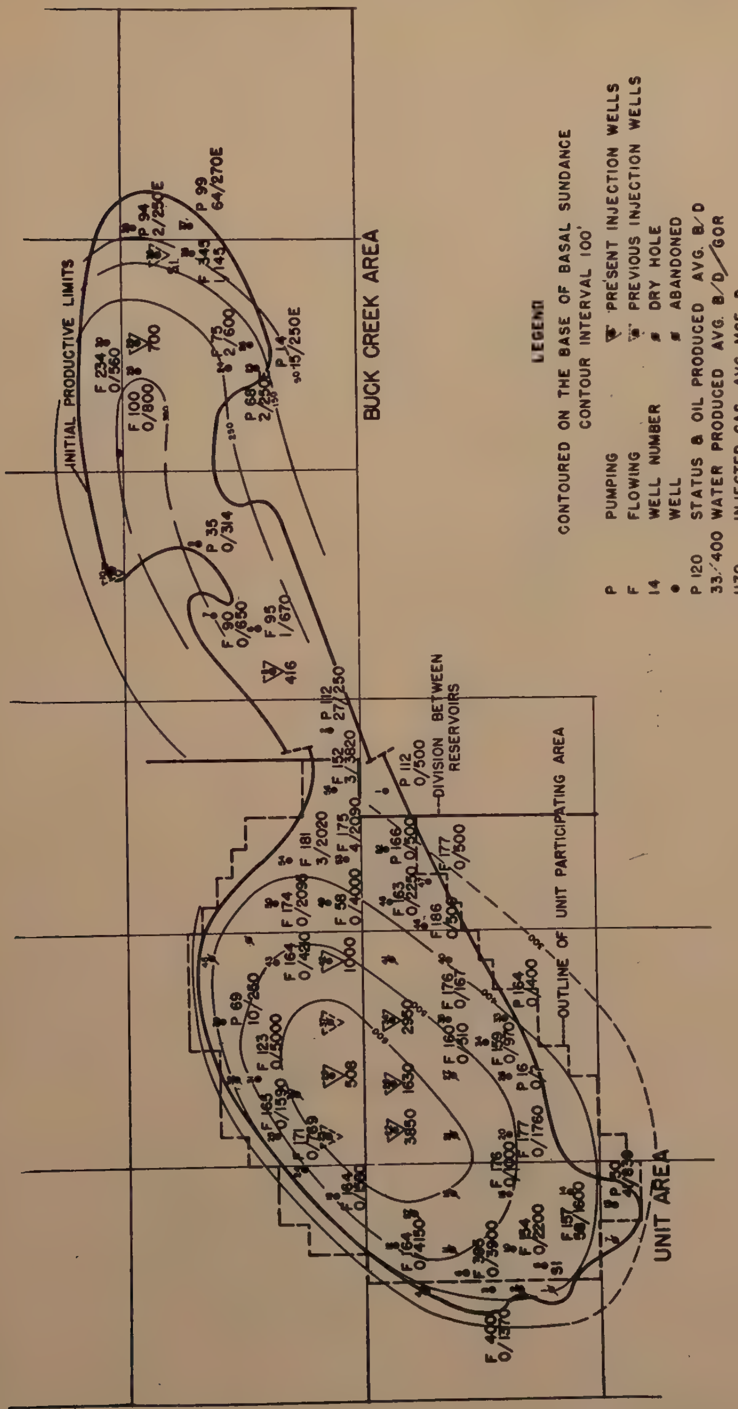

FIG 7—WELL STATUS, LANCE CREEK FIELD, JUNE 1942.

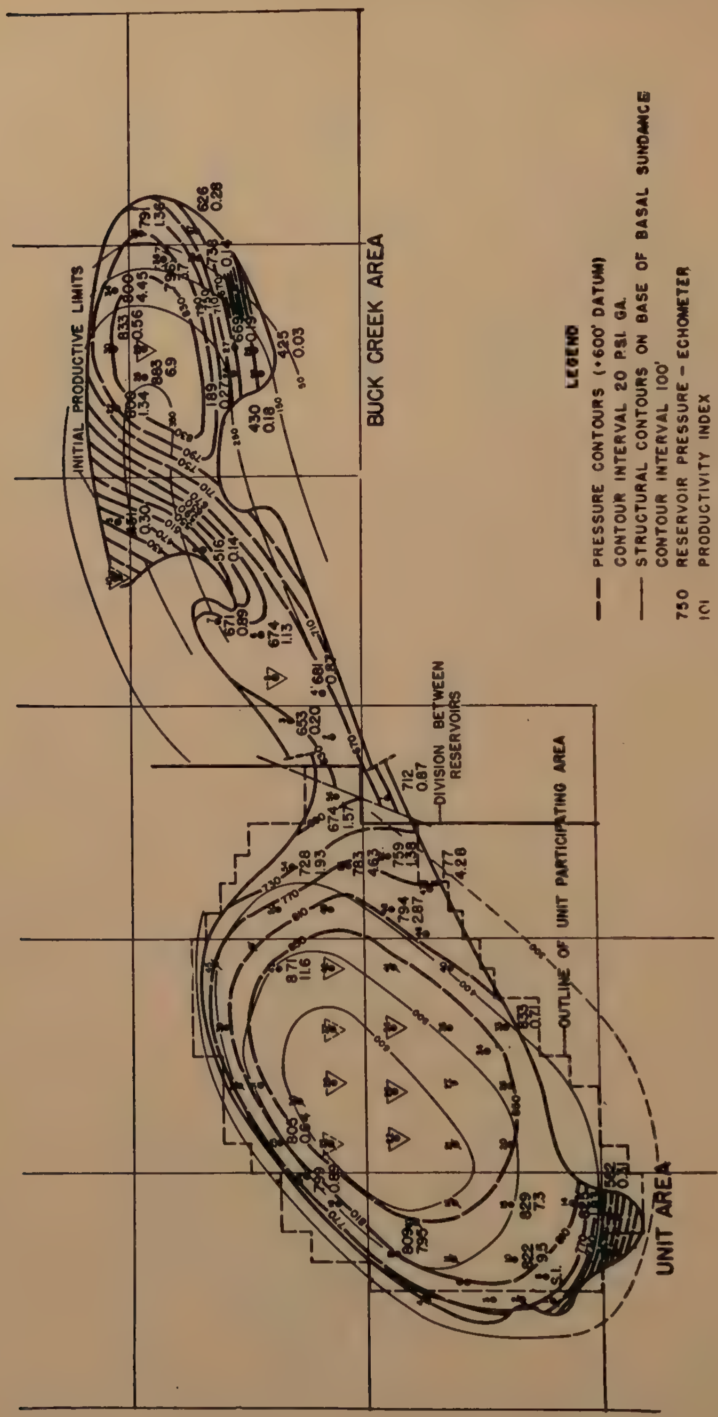

FIG 8—RESERVOIR PRESSURE, LANCE CREEK FIELD, SEPTEMBER 1942.

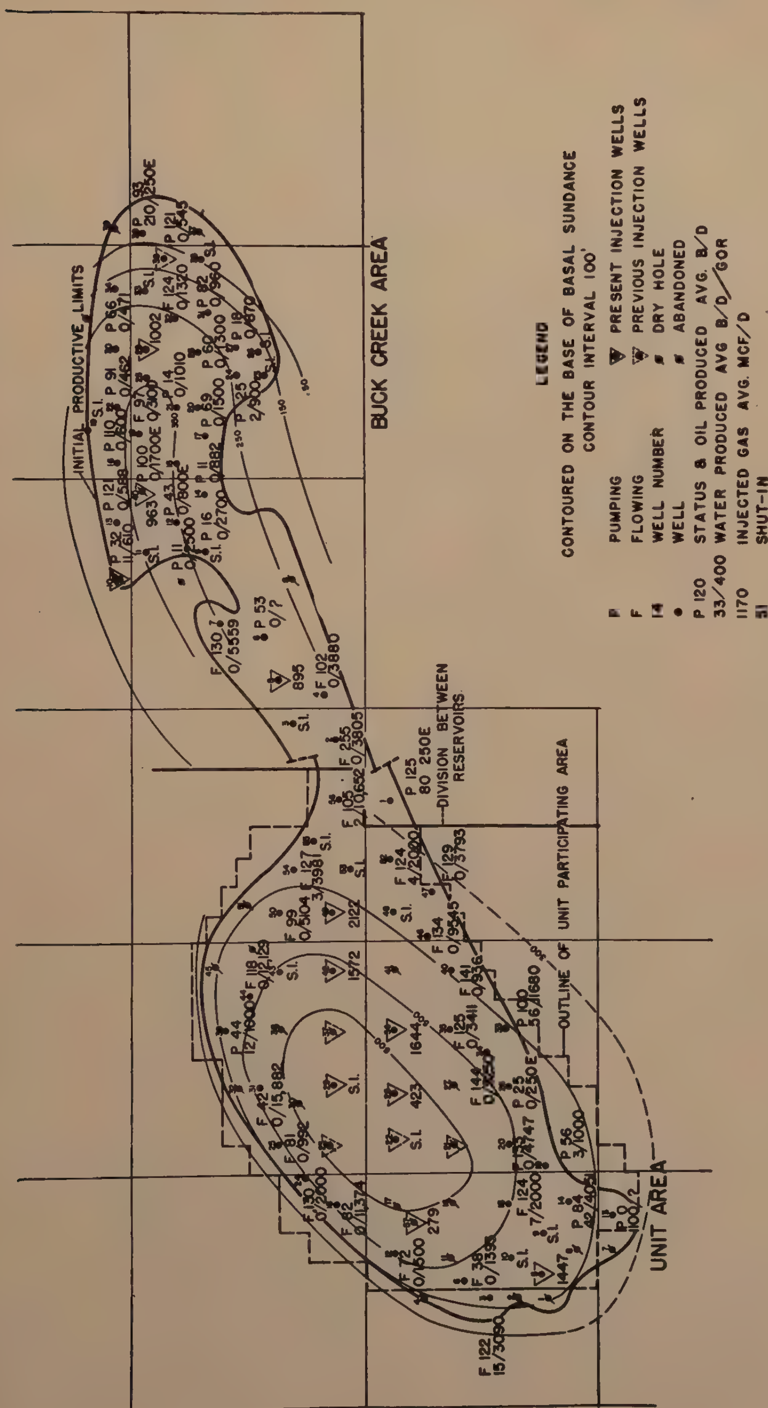

FIG 9—WELL STATUS, LANCE CREEK FIELD, JUNE 1947.

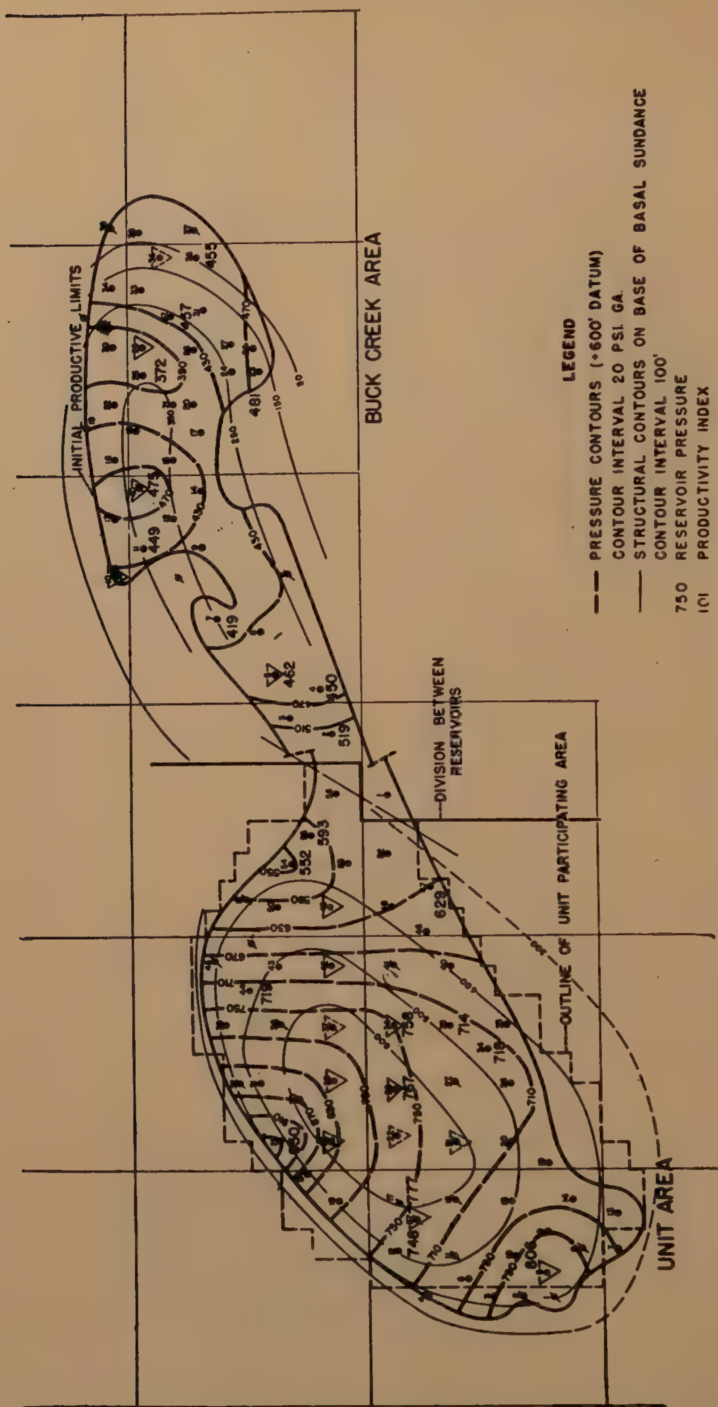

FIG 10—RESERVOIR PRESSURE, LANCE CREEK FIELD, SEPTEMBER 1946.

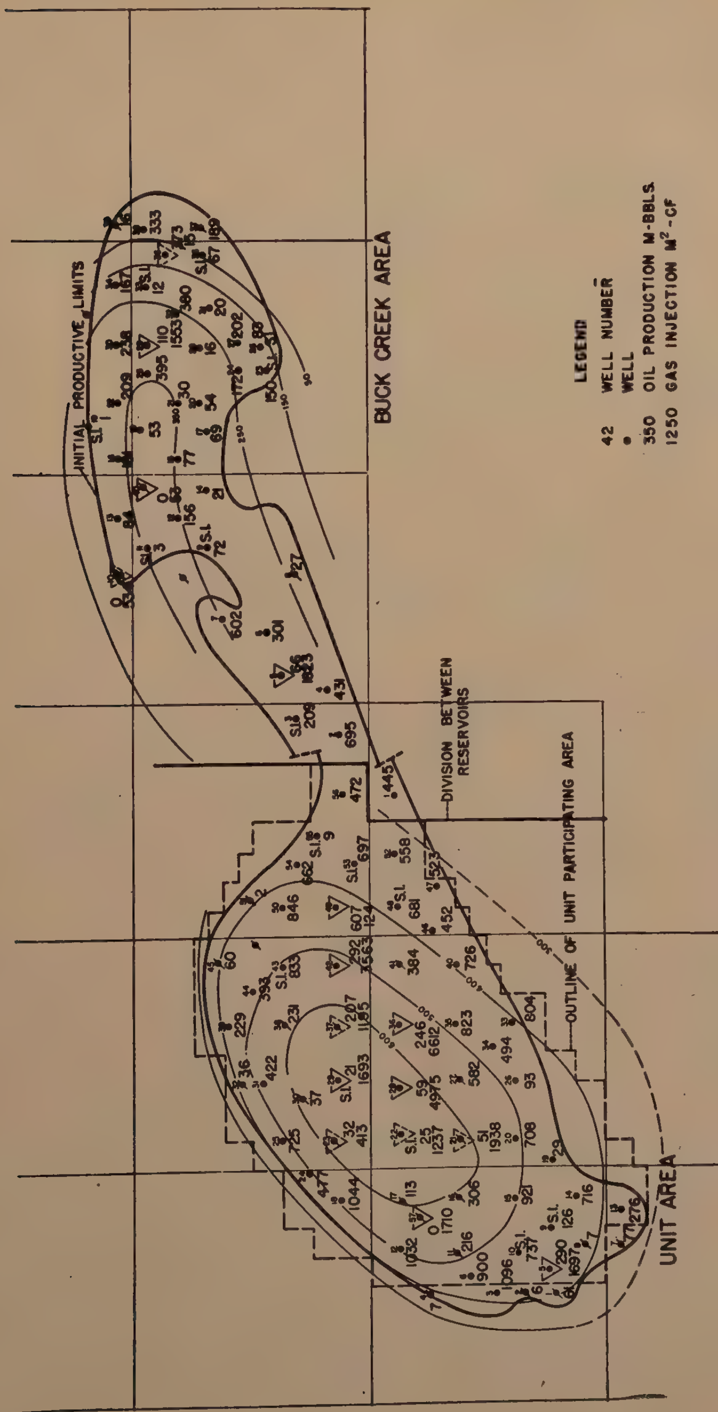

FIG 11—CUMULATIVE OIL PRODUCTION AND GAS INJECTION TO JULY 1, 1947, LANCE CREEK FIELD.

per pound. The calculated expansion of oil and gas then in the reservoir (using the bulk-volume estimate of initial content minus past production) is some 51,000 bbl the second instance, indicates that all of the oil was not below its saturation pressure in the first higher pressure case, and not all oil was releasing gas from solution—con-

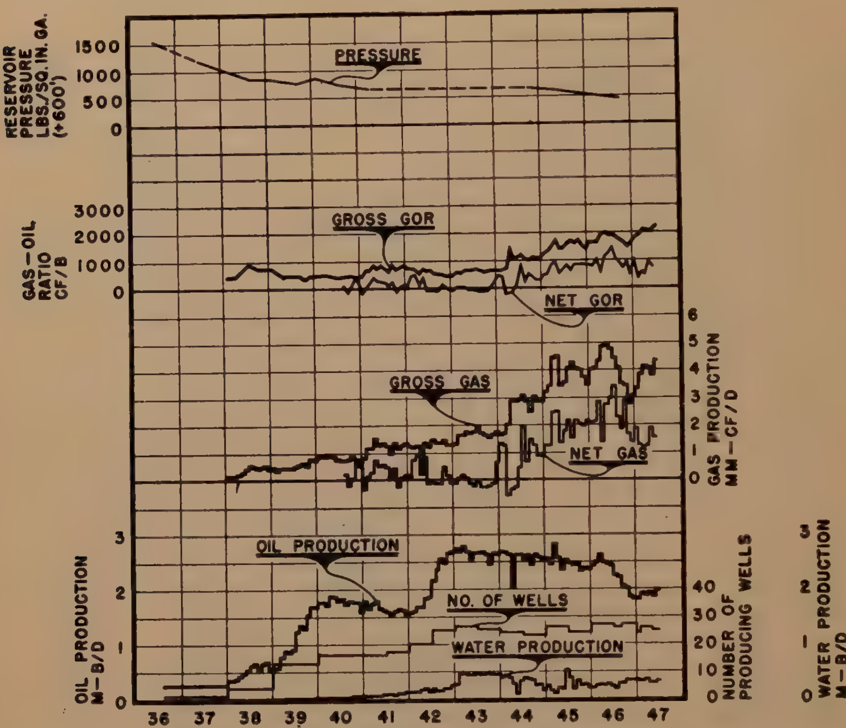

Fig 12—Performance curves, Buck Creek area.

per pound. Thus production of oil and gas was some 20 pct less than that corresponding with estimated oil and gas content of the reservoir. For the period from July 1937 to March 1938, production averaged about 18,000 bbl per pound pressure decline, and the oil and gas volume averaged about 63,500 bbl per pound measured at mean formation pressure. The calculated expansion of the oil and gas then in place is about 67,000 bbl per pound. In this period production was only about 5 pct less than that calculated from the oil and gas content. Therefore the greater divergence of the earlier performance from that calculated, as compared with the lesser divergence in trary to the assumption implicit in the method of analysis.

These previous calculations have been made on the assumption that water encroachment was negligible in retarding pressure decline. In order for water *encroachment* to have lessened pressure decline by even 10 pct, it would have had to average 2800 bbl per day from inception to March 1938, and 3400 bbl per day from July 1937 to March 1938, when gas injection began. Water *production* has leveled off since 1943, at less than 200 bbl per day. During this period only five more wells began to produce water and all but one of these had water cuts of 10 pct or less.

Water encroachment probably did not greatly exceed water production since 1943, thus indicating that rate of water encroachment was also relatively low prior to

feet of gas were returned to the reservoir. This gas injection is 89 to 93 pct replacement of the volume of produced fluids during this period, depending on what

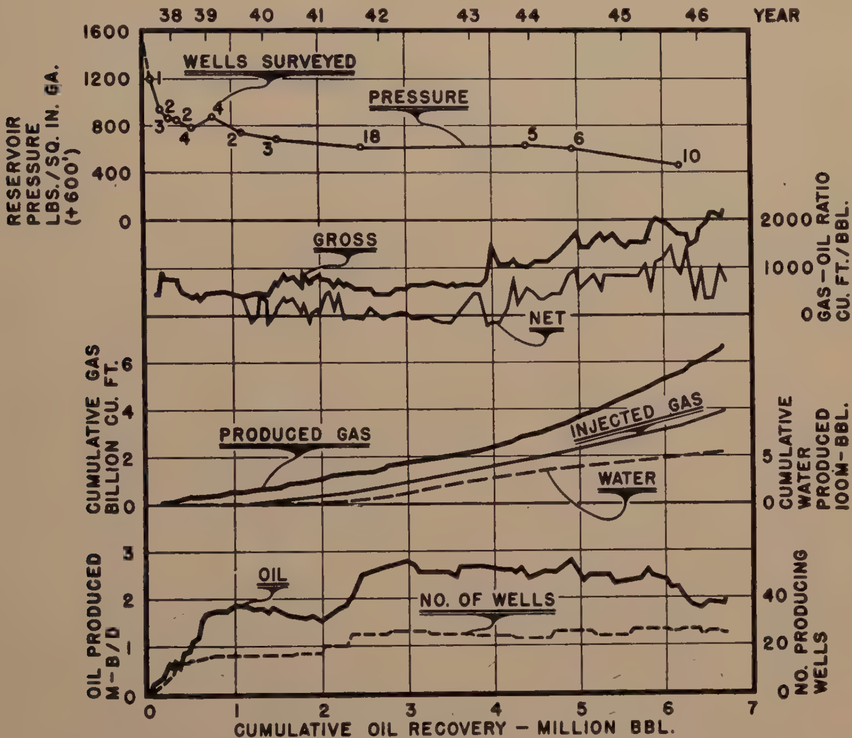

FIG 13—RESERVOIR PERFORMANCE VS CUMULATIVE RECOVERY, BUCK CREEK AREA.

1938. This information, combined with the fact that cumulative water production of only 365,000 bbl has accompanied recovery of 22,500,000 bbl of oil provides excellent evidence that water encroachment was insufficient to affect significantly the previous comparison between the pressure-production relation and bulk-volume estimate of initial oil content even during the period of rapid pressure decline prior to gas injection.

Between February 1938 (when gas injection began) and the last general pressure survey in September 1946, some 15 million barrels of oil and 26.8 billion cubic feet of gas were produced, while 23 billion cubic

correction to metered gas is made in correcting separator gas and tank oil to volume at reservoir conditions; separator pressures have varied from 5 to 30 psi. The calculated expansion of reservoir fluids from the average datum pressure of 845 psi at the beginning of gas injection to the average datum pressure of 745 psi at the end of the period was about 9.5 to 10 pct of the volume of produced fluids. The sum of injected gas volume and calculated volume of expansion of reservoir fluids thus ranges from about 98.5 to 103 pct of the volume of produced oil and gas. Of course, it must be realized that this close agreement is somewhat fortuitous because of the many possi-

bilities of error in field measurement of gas, unavoidable losses of gas not metered, use of average formation pressures in calculating the volumetric balance, and uncertainty of converting separator oil and gas volumes to the proper volumes at reservoir pressures and temperatures. However, it is sufficiently accurate to indicate rather minor net water encroachment into the oil zone. As of June 1947, there were 10 remaining wells producing water with an overall average water cut of 15 pct. The portion of the reservoir in the area invaded by water is some 15 to 20 pct of the original oil volume, but this can by no means be considered to be effectively swept by water, since the produced water volumes are so low and since the affected wells still account for about 40 pct of the present oil production.

Buck Creek Area Reservoir

The productive limits of the Buck Creek area Basal Sundance reservoir, as outlined on the isopach map in Fig 2, include some 860 acres with an average net pay thickness of about 37 ft out of an average total zone thickness of 90 ft. Fewer cores were available from this pool than from the Unit area, but those available indicate lower porosity, lower permeability, and in general poorer characteristics. The porosity is estimated to average 22 pct and interstitial water saturation 30 pct. These data indicate a total bulk volume of 31,500 acre-feet, containing about 27.5 million barrels of tank oil initially.

In this reservoir early development was too slow and coverage of the reservoir in subsurface pressure surveys too incomplete to permit accurate independent volumetric balances from the pressure-production relation. However, the data can be used in a manner similar to the previous analysis of the Unit area reservoir performance. Up to September 1942, 2.5 million barrels of oil and 1.3 billion cubic feet of gas had been produced with a decline in average datum pressure to 610 psi. During this period 0.6 billion cubic feet of gas had been injected into the reservoir. Calculating back to initial conditions indicates an average saturation pressure of 700 psi, which is not out of line with the early drop in pressure as indicated on the reservoir-performance curves, Fig 12 and 13. The apparent increase in pressure early in 1940 resulted from measurement of well pressures in the more recently developed part of the field and probably is not a true picture of reservoir performance.

From September 1942 to September 1946, 3.7 million barrels of oil and 4.3 billion cubic feet of gas were produced, while 2.7 billion cubic feet of gas were injected. Average datum pressure dropped from 610 to 460 psi. The gas injection amounts to 67 to 76 pct of the volume of produced fluids, and the calculated expansion of oil and gas present at the beginning of the period is 37 to 42 pct of the volume of produced fluids. The total injected gas volume and expansion of reservoir fluids thus amounts to 104 to 118 pct of the produced fluids. The range of uncertainty of balance is again caused by difficulty in correcting separator oil and gas volumes to corresponding volume in reservoir environment.

The approximate volume of water encroachment cannot be determined by volumetric balance, since produced fluids are less than the injected gas and calculated expansion of reservoir fluids. Water encroachment has affected 10 wells and some 13 pct of the reservoir volume. Water production has totaled about 580,000 bbl during production of 6.7 million barrels of oil. Water encroachment is relatively greater in the Buck Creek area than in the Unit area, but here, too, it is not of major importance.

Gravity Drainage

Because of the difference in their densities, gravitational forces tend to cause

separation of oil and gas. In an underground petroleum reservoir, this is partly offset by capillary forces, which primarily control ultimate segregation, and frictional or viscosity effects, which primarily control rate of segregation. Gravity segregation can be minimized by production of upstructure wells at high gas-oil ratios; it can be made quite effective by unit operation with countercurrent flow of oil and gas; and it can be made most effective with sufficient gas injection upstructure to fill the space voided by downdip drainage of oil. Gravity drainage cannot be increased—according to the popular misconception—by "piston-like" action of high-pressure gas in a gas cap. Gas pressure can force oil to flow downdip at a rate faster than gravity drainage, but gas will flow also in accordance with effective permeabilities of the rock to gas and to oil and in accordance with potential gradients in each of gas and oil phases. Overall efficiency in terms of gas-oil ratios will be better than gas injection into a similar flat reservoir, but it will not be the same as true gravity drainage in which no gas but solution gas is produced.

Making only the one basic assumption of applicability of Darcy's law of fluid flow in porous media and using measurable physical characteristics of the reservoir rock and fluids, it is possible to calculate with reasonable accuracy the *maximum* rate at which oil can drain by gravity from upstructure to downstructure regions. Certain features of the operation of the reservoir can reduce the rate of drainage, but at least the maximum rate has practical significance in determining whether a reservoir can be exploited at a desired rate by the gravity drainage method.

Darcy's law for downdip flow of oil (essentially two-dimensional flow in the "curved" plane of the reservoir formation) may be expressed as:

$$Q_o = 1.127 \frac{K_o HL}{U_o FVF}\left(\frac{dP}{dD} - d_o \sin \alpha\right) \quad [1]$$

Where

Q_o = rate of oil flow, bbl tank oil per day.

K_o = effective permeability to oil, darcys.

H = thickness of formation exposed to flow, ft.

L = length of formation exposed to flow (measured along strike or structure contour).

U_o = viscosity of oil, centipoise.

FVF = formation volume factor of oil.

P = pressure in oil phase, psi.

D = distance along dip of formation, ft.

d_o = density gradient of oil, psi per foot.

$\sin \alpha$ = sine of dip angle.

1.127 = factor to convert darcys to barrels, feet, pounds per square inch, and day system of units.

Since maximum gravity drainage will occur in presence of static gas, and since pressure at each point in the reservoir will be the same in gas and oil phases except for a small difference in capillary pressure, the downdip pressure gradient in the gas-oil region may be calculated from the gas density gradient and will be given by the formula:

$$\frac{dP}{dD} = d_g \sin \alpha \quad [2]$$

where

d_g = density gradient of gas, psi per foot.

Combining this with Eq 1 gives:

$$Q_o = 1.127\, K_o H_o \frac{(d_o - d_g)}{U_o FVF} L \sin \alpha \quad [3]$$

for *maximum* gravity drainage. Since reservoirs are not perfectly symmetrical and fluid withdrawals are not uniformly distributed, the gas-oil contact will advance faster downdip in some areas than in others. Since the tendency exists for oil to seek a common level, there will be a lateral component of flow to compensate for the unequal advance, and the actual flow path will exceed the shortest downdip path and thus decrease the net downdip

flow velocity. Effects of individual well-pressure drawdown will also alter the flow pattern and reduce the flow velocity.

Since oil production is a depletion process, some gas must flow downdip to fill voids depleted of oil; the previous formulas must be considered a simplification of the behavior of a very complex flow system, but approximate calculations indicate that the error is not too large.

In Eq 3, three separate groups of factors combine to control possible gravity drainage of oil. These are $L \sin \alpha$, a function of the geometry of the reservoir; K_oH, the product of effective permeability and pay thickness; and $\frac{(d_o - d_g)}{U_oFVF}$ a function of the properties of oil at reservoir conditions. The function $L \sin \alpha$ may be evaluated by plotting structure cross sections along dip lines to determine dip angles, and then making a summation of short lengths of structure contour multiplied by the sine of the dip angle. The effective permeability times thickness can be determined from core analysis and well tests and, so far, must be predicted for future conditions from laboratory tests and comparison with other reservoirs. The function $\frac{(d_o - d_g)}{U_oFVF}$ can be calculated from subsurface or recombination sample analysis data of reservoir fluids.

To check this analysis, the effective permeability to oil has been calculated from estimated regional migration of oil in the Unit area reservoir and datum pressure gradients, and compared with effective permeabilities calculated from productivity index tests.

The function $L \sin \alpha$ was evaluated for the +600-ft, +500-ft, and +400-ft contours on the base of the Basal Sundance within the productive limits of the reservoir. Values obtained were 910, 2431, and 1090 ft, which correspond to average dips of 3.8°, 7.1°, and 5.6°, respectively. Lesser average dip for the +400-ft contour exists because only part of the southeast flank has wells below that level. Maximum dip within the affected area along the northwest flank is 13°, and average dip throughout the rather large southwest, south, and southeast mid flank area is about 4.5°.

Table 3 summarizes production below each contour level, calculated effective permeability assuming production due to maximum gravity drainage, and effective permeability calculated from mid-flank-well productivity index tests for June 1938, June 1942, and June 1947. The large difference between the permeability calculated for the +600-ft contour and the +500 and +400-ft contours indicates not all production below +600 was draining

TABLE 3—*Comparison between Reservoir and Well Permeability, Unit Area, Lance Creek Field*

Contour Level, Ft	June 1938		June 1942		June 1947	
	Production Below Level, Bbl per Day	Calculated[a] Effective Permeability, Darcy-feet	Production Below Level, Bbl per Day	Calculated[a] Effective Permeability, Darcy-feet	Production Below Level, Bbl per Day	Calculated[a] Effective Permeability, Darcy-feet
+600	9335	19.3	3743	7.8	2272	4.8
+500	7096	5.5	3115	2.4	1901	1.5
+400	2202	3.8	1263	2.2	760	1.3
Average permeability from mid-flank well PI tests, Darcy-feet..	3.5		4.7			
Core-analysis Permeability, Darcy-feet...	13.5					

[a] Assuming all drainage due to gravity and equal to production.

across this line. Obviously this was correct in June 1942 and June 1947, since recovery for the pool was about 23 and 31 pct of initial oil in place, respectively, and the volume within the +600-ft contour is only 20 pct of the total reservoir volume.

In June 1938, gravity drainage could very easily have exceeded oil production, since some downstructure wells had declining gas-oil ratios after gas injection started when the rate of pressure decline and release of gas from solution in oil were retarded. The pressure survey in April 1938, Fig 6, indicates that in many areas the pressure gradients were less than the density head of oil while in other areas they were greater. It is quite probable that actual effective permeabilities were somewhat higher than those shown in Table 3 for the +400 and +500-ft contours.

Downdip pressure gradients cannot be determined from the September 1942 survey, Fig 8, because no top-structure well pressures were measured, but in June 1942 many gas-oil ratios were increasing, indicating invasion of free gas. Probably not all the oil production was replaced by drainage and most likely the density head was exceeded. The calculated effective permeabilities for the +400 and +500-ft contours are probably too high. The higher well permeabilities are due to inclusion of some uncertain productivity indexes, resulting from fluid-level finder tests where drawdowns were too small in relation to accuracy of method.

In June 1947, most wells had free gas production, indicating free gas invasion in all parts of the reservoir. The oil drainage rate was most likely less than production and the pressure gradients were in excess of the density head. The September 1946 survey (Fig 10) showed more than 200 psi difference in datum pressure between top of structure and the low-structure east part of the reservoir. About 90 psi is equal to the density head of oil. In other parts of the reservoir the pressure gradients were more nearly equal to the density head of oil. Actual effective permeabilities were less than those calculated in Table 3.

These comparisons, although based on approximate oil-drainage rates and pressure gradients, do provide order of magnitude comparison between reservoir and well permeabilities, and furthermore, validate the basic assumption involved in the gravity drainage analysis. More complete well testing and pressure surveys, coupled with accurate individual well-production gauges, would have permitted more accurate analysis and would have permitted even more effective utilization of gas injection.

The data indicate that effective permeability has declined to less than 10 pct of core-analysis specific permeability when 31 pct recovery has been attained. Unfortunately, no initial productivity index tests are available, but initial production as high as 5200 bbl of oil per day indicates permeability of the same order shown by core analysis.

A similar comparison between reservoir and well permeabilities has not been made for the Buck Creek area reservoir. Irregular sedimentary conditions and geometry of structure coupled with competitive operation in this nonunitized pool make it almost impossible to segregate effects of gravity drainage. For example, the productive limits near wells 9 and 10 are determined by reservoir conditions and not structural location. In September 1942, datum pressure gradients were updip to the top structural locations, prior to gas injection in this part of the reservoir, and thus any flow was in the opposite direction from that due to gravity. Undoubtedly, effects of gravity segregation are present, since dips are steep enough and some well permeabilities are high enough, but quantitative evaluation is not possible. Conclusions based on cumulative production by wells in Fig 11 and by areas in Table 3 should be tempered in view of this discussion.

Gravity drainage of oil has been found to depend not alone on steepness of structure but on the composite effect of structure, permeability, and properties of the reservoir fluids. Thus, extremely low viscosity of oil in the range of 0.35 to 0.45 centipoise has permitted quite good gravity drainage with only moderate permeability and dips. It is often stated that maintenance of pressure at maximum levels is desirable for good gravity drainage by keeping oil viscosity low. However, gas in solution and pressure also affect other properties of oil which are directly involved in gravity drainage. High pressure and gas in solution are favorable to low viscosities, but low pressure and minimum amount of gas in solution are favorable to low formation-volume factor and maximum difference between densities of gas and oil. The active gravitational force, of course, is proportional to the difference in densities, and low formation-volume factor is desirable because it is volume of *tank* oil drainage—not volume of oil under reservoir conditions—that is of economic importance.

Average properties of Lance Creek Basal Sundance crude oil, based on subsurface sample analyses conducted by the U. S. Bureau of Mines Petroleum Experiment Station, Laramie, Wyoming, are shown in Fig 14 extended to 1600 psia, the highest probable initial saturation pressure of any oil in the reservoir. The function $\frac{(d_o - d_g)}{U_o FVF}$, which is the group of properties directly entering into the gravity drainage formula, is also plotted. It reaches a maximum at 1000 psia and is only 20 pct less at 100 psia than at the maximum pressure of 1600 psia. Considering only viscosity, it amounts to a 50 pct reduction at 100 psia compared with 1600 psia.

Gas-oil Ratio

The Unit area reservoir has provided an excellent case history of gas-oil ratios with primary gas injection and unit operation of a reservoir where gravity drainage has been important. Following unitization, average ratios were reduced to as low as 850 cu ft per barrel by shutting in high-ratio wells and by reduction in producing rate. Ratios as low as 1000 were maintained through 1939, when some 16 pct of oil initially in place had been recovered. Since then gas-oil ratios have increased at an accelerating rate with a corresponding decrease in oil withdrawal in order to keep gas production within plant capacity. This is the history of most pressure-maintenance operations—a compromise between oil rate limitation and plant enlargement then becomes the remaining engineering problem. It is important to note the gas-oil ratio "peaks" near midsummer of each year since 1941 (Fig 6). The increase is caused partly by temperature effect on separation of gas from this high-gravity crude, but much of the decrease has been effected by reduction of oil-production rate and by shutting in wells. Although the number of producing wells has declined only from 33 to 23 since unitization, the number of shut-in wells, abandoned wells, and producing wells converted to input wells has increased by 20. The difference is due to additional drilling. In addition to reductions in production rate and shutting in wells, control of gas-oil ratio has been attempted by use of packers, intermitters, and alternating production from adjacent wells to permit a "resaturation" period.

A temperature survey was run in Unit area well No. 12 in October 1945, to find the point of gas entry and permit an effective shutoff or to determine whether the entire pay section had been effectively swept with gas. A gas-oil contact was indicated at 3885 ft with productive sand from 3837 to 3919 ft. Core analysis and sample description indicated a coarse (420 md) sandstone from 3871 to 3878 ft. A formation packer was set at 3886 ft, leaving 33 ft of effective pay in open hole below the packer. About 185 bbl of oil was pumped into the

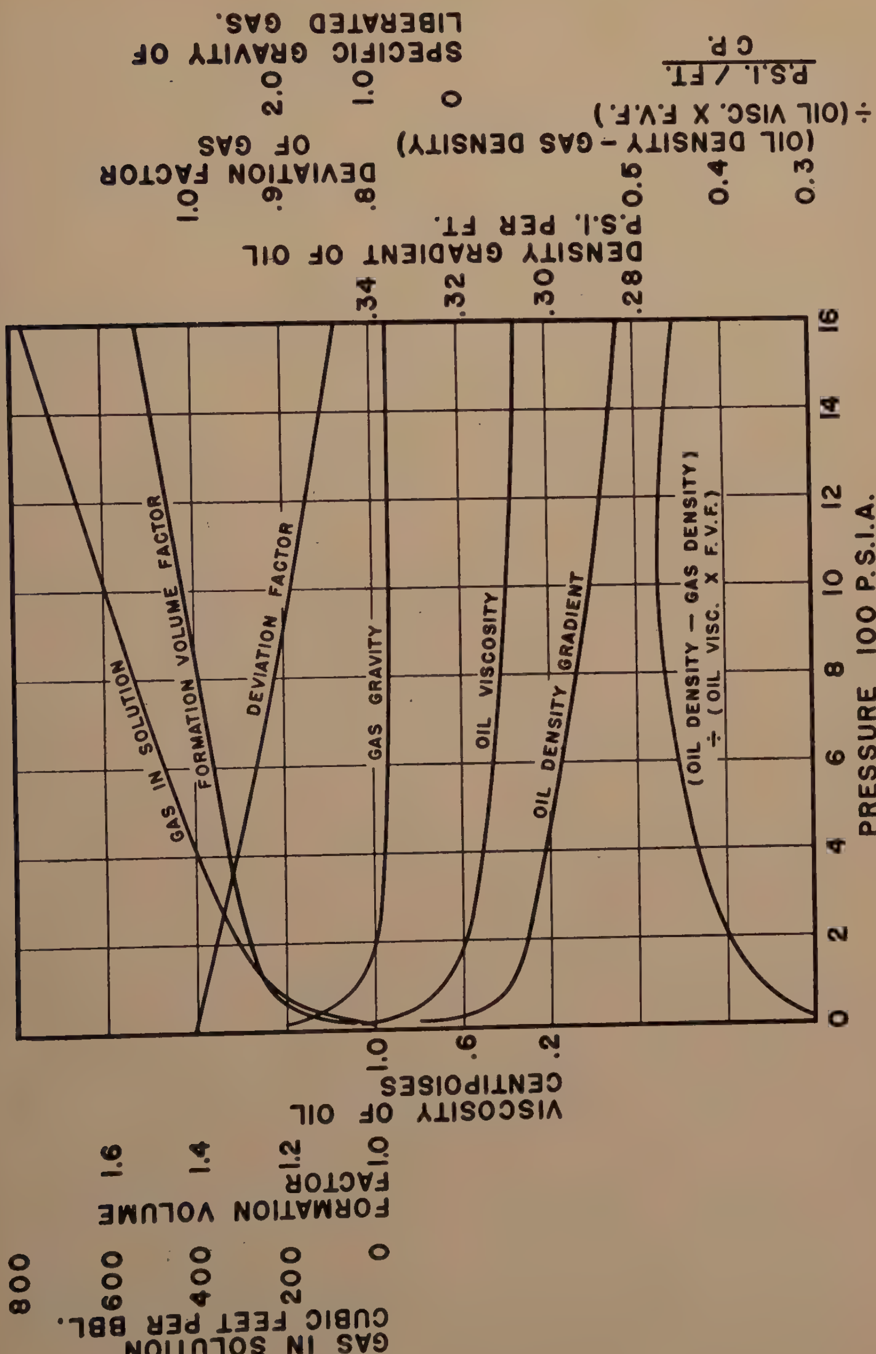

FIG 14—COMPOSITE ANALYSIS DIFFERENTIAL VAPORIZATION AT 155°F, BASAL SUNDANCE CRUDE OIL. Basic data from U. S. Bureau of Mines, Laramie, Wyo.

gas zone above the packer, and a bottom-hole choke was installed to prevent excessive pressure drawdown. Previous to recompletion, the gas-oil ratio was about 6000 cu ft per barrel, increasing steadily; since selective recompletion, the well has produced some 72,000 bbl to July 1947, with an average gas-oil ratio of 1500. Estimated saving in gas production to July 1947, by shutting off 7 ft of highly permeable gas-saturated sand, is some 350 million cubic feet.

Similar recompletion with Unit area well No. 6 was partly successful in that the gas-oil ratio was reduced from 13,000 to 4300 cu ft per barrel; but testing of well No. 10 showed high ratio production both above and below the packer. An intermitter has been fairly successful in reducing gas-oil ratios of well No. 39, and alternating production between wells 18 and 25 at a monthly cycle has reduced gas-oil ratios until recently from about 10,000 to 1500 cu ft per barrel.

These tests and production techniques suggest that the injected gas has swept primarily through the more permeable beds, leaving oil locked in the tighter parts of the reservoir till overall reduction in reservoir pressure or localized reduction in pressure by selective completion of zones permits expansion of gas released from solution to expel part of this oil. Further evidence that high gas-oil ratios do not necessarily mean thorough recovery of oil are tests of well No. 49, conducted in December 1946, prior to converting it to an input well. This well tested two days each at 24/64-in. and 32/64-in. choke produced an average of 50 and 89 bbl per day with tubing pressures of 530 and 485 psi, respectively, and with all gas-oil ratios between 21,000 and 23,000 cu ft per barrel. The productivity index averaged about 3. It is obvious that this well had previously been shut in to reduce gas production and not because of lack of ability to produce oil.

Variations in gas-oil ratio of this pool that have been made by shutting in wells selectively, changing rates, redistributing production among wells, selective completion, etc., clearly indicate that there is no single valued K_g/K_o or relative permeability-saturation relation that may be simply applied to prediction of reservoir performace. Undoubtedly, at any particular stage of depletion and particular producing rate some minimum gas-oil ratio exists, but the actual gas-oil ratio can vary widely with the operating control applied.

At similar stages of depletion, the gas-oil ratios in the Buck Creek area reservoir have been somewhat lower than those of the Unit area reservoir. Part of this is due to slightly greater relative water encroachment and to less shrinkage of formation oil because of the somewhat lower saturation pressure; but part might also be caused by the lower level of pressure maintained, which would permit gas released from solution to expel oil from the tighter parts of the reservoir. It is anticipated that a gratifying increment of production over and above that indicated by production decline in the Unit area reservoir will be recovered when eventually the pressure is reduced.

Gas-oil Ratios, Gravity Drainage, and Production Rates

Since gas-oil ratios have been subject to partial control by pool production rate, it is important to correlate this performance with rate of gravity drainage to facilitate use of these data in predicting performance of other reservoirs. In 1938 and 1939, the production rate was about the same as the gravity drainage rate and gas-oil ratios remained at about 1000 cu ft per barrel during this period when recovery ranged from 9 to 16 pct of oil in place initially. Production averaged about 7000 bbl per day, which is some 40 pct of the theoretical maximum gravity drainage assuming effective permeability equal to core-analysis permeability. During 1942, gas-oil ratios averaged about 2000 cu ft per barrel, when recovery was 22.5 pct and production rate

25 pct of theoretical maximum gravity drainage rate based on core-analysis permeability. Actual gravity drainage, of course, was less than production because of greatly reduced effective permeability. By June 1947, gas-oil ratios had reached 4500 when recovery was 31 pct and when production rate was 13 pct of theoretical maximum gravity drainage. Again actual gravity drainage was less than production because of greatly reduced effective permeability. In converting to equivalent performance for other reservoirs, the low viscosity of oil of about 0.42 centipoise should be noted. Approximate equivalent free gas-oil ratio can be obtained by multiplying by ratio of oil viscosities and by ratio of pressures of this and the comparative pool.

Similar gravity drainage analyses of three other unitized primary gas-injection, pressure-maintenance projects have shown similar results. In one, gas-oil ratios had reached 5000 cu ft per barrel at 12 pct recovery when production rates were about 30 pct of theoretical gravity drainage assuming effective permeability equal to core-analysis permeability. Reservoir pressure was about 2100 psi and oil viscosity about 0.6 centipoise. Few wells had been shut in for control of gas-oil ratio but production had been allocated to wells to aid in control.

In a second project, average gas-oil ratio has reached 6000 cu ft per barrel at 14 pct recovery with 30 pct of oil wells shut in for control of gas-oil ratio. Production rate is about three times theoretical maximum gravity drainage based on limited core analyses, and datum pressure gradients in the oil zone have exceeded the density head of oil by a factor of 4 to 7. Reservoir pressure is 1050 psi and estimated oil viscosity in the reservoir is about 1.8 centipoises.

In a third project, gas-oil ratios remained at essentially solution gas to about 20 pct recovery of oil in place initially. It reached 1000 cu ft per barrel at 30 pct recovery. Pressure gradients were practically unmeasurable (within instrumental accuracy) throughout the reservoir and were considerably less than the density head of oil. Control of gas-oil ratio was obtained, at least in the earlier stages of depletion, by regulation of individual well rates to maintain tubing submergence. Average permeability was in excess of one darcy and sand thickness ranged up to 500 ft. Segregation in this case was primarily vertical in section as compared with regional drainage essentially parallel to the bedding planes in Lance Creek and the other example reservoirs. This type of control of gas-oil ratio requires that satisfactory production rates be obtainable with individual well-pressure drawdown equivalent in head to a small part of the exposed section.

Summary

Reservoir performance of the Unit area Basal Sundance reservoir and of the smaller Buck Creek area Basal Sundance reservoir at Lance Creek have been presented in graphic form and as maps of well status and pressure at various stages of depletion. A fair degree of segregation of oil and gas has been obtained and gas-oil ratios controlled by shutting in wells, regulating pool-production rate, and by selective completion of wells. Good agreement between bulk volume estimates of initial oil and gas content and volumetric balance of produced and injected fluids, coupled with limited water production relative to oil production, indicate only minor net water encroachment. Thus, reservoir performance has been primarily that of a volumetric type reservoir with added effects of gravity segregation of oil and gas augmented by pressure maintenance through structural injection of gas.

A method of estimating maximum gravity drainage has been developed and compared with performance of the Unit area reservoir. Good order of magnitude agreement between reservoir and well permeabilities was obtained from the available

pressure, production, and productivity index data, thus validating the major assumption of applicability of Darcy's law in the gravity drainage analysis.

Performance of this reservoir has clearly shown the benefits resulting from unit operation, which has permitted proper control of the reservoir (through absolute freedom in production of each individual well) to utilize gravity segregation and gas injection to their greatest effectiveness.

Acknowledgments

The authors wish to acknowledge the excellent background information prepared by the Unit Engineering Committee; the invaluable assistance rendered by Mr. Nat Slagter, Unit Coordinator, in compiling and checking field data; and the pressure-volume-temperature and gas-solubility data available only through the foresight of the U. S. Bureau of Mines under supervision of Mr. Ralph H. Espach.

Appreciation is also expressed to Argo, Continental, and Ohio Oil Companies for permission to publish this material.

DISCUSSION

W. M. Jones*—The effective utilization of gravity drainage in producing oil from steeply dipping reservoirs like those encountered in the Rocky Mountain region plays an important part in the oil recovery from those fields. It is evident, however, that the maximum benefits of gravity drainage are obtained only when the producing rate does not exceed the gravity segregation of the oil and gas in the reservoir. We are thus confronted with the problem of evaluating the maximum rates of segregation that may be expected throughout the depletion of reservoirs of this type. The paper by Elkins, French and Glenn presents an approach to this problem which indicates reasonable agreement with the observed performance of the Lance Creek Sundance reservoir.

Two factors employed by the authors in their method of estimating the maximum segregation rate warrant some discussion. The first matter of concern is that the equation employed requires the free gas in the reservoir to remain stationary while the oil migrates downdip. Actually, once permeability to gas is established in the reservoir there will be a counterflow of gas moving upstructure while the oil moves down. This upward flow of gas also tends to impede the downdip flow of oil, thus retarding further the rate of gravity segregation.

The second factor involves the value for the relative permeability to oil that is employed in the authors' gravity segregation equation. The permeability values used in the analysis apparently were derived from productivity indexes and the radial flow equation. It is known that saturation conditions, and therefore, the relative permeabilities in the immediate vicinity of the well bore, usually differ appreciably from the permeabilities farther back in the formation. The gravity drainage that affects the overall reservoir performance is in reality the regional migration of oil, which takes place principally through the parts of the formation some distance from the well bore. Therefore, the relative permeabilities to oil derived from PI tests do not, under ordinary circumstances, represent the K_o values that should be used in the authors' equation. The difference between the relative permeabilities immediately surrounding the well bore and those back in the formation depend principally upon the well's previous history, the conditioning of the well prior to the tests and the producing rates during the tests. It may be possible to obtain more representative values of relative permeability for use in the gravity segregation equation by the careful selection of wells, proper conditioning, and precise control during the tests. Generally speaking, however, the pressure drawdown in the vicinity of a well during production, with the resulting increase in gas saturation, will indicate K_o values from PI tests somewhat lower than the relative permeability of the reservoir as a whole.

The authors' equation was applied by the writer to another Rocky Mountain field in an attempt to calculate the maximum rate of gravity segregation. The segregation rate as calculated by this method indicated a segregation rate amounting to only some 30 to 40 pct of that predicted from actual field performance. It is believed that the greatest part of this discrepancy is due to the method of selecting K_o values. Actually the two

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factors mentioned in this discussion of the gravity segregation formula partially compensate one another. Thus the application of the equation to reservoir conditions, other than those selected by the writer, may show somewhat closer agreement with observed field performance.

Another point discussed in the paper which prompts some comment is the matter of partial versus complete pressure maintenance in reservoirs of this type. The success of operating a reservoir under partial pressure maintenance depends upon the properties of the reservoir fluids and formation characteristics. The authors apparently favor partial pressure maintenance as the ideal method of reservoir control, although the data show that after only 31 pct oil recovery from the Sundance reservoir the relative permeability to oil has decreased to approximately 10 pct of the original value. It appears to the writer that even with the increase in the difference in densities of the oil and gas phases and the reduction in the formation-volume factor in the oil which partial pressure maintenance affords, the increased gas saturation and subsequent reduction in K_o values, along with some increase in the viscosity of the oil, are definitely not desirable.

L. F. Elkins (author's reply)—Mr. Jones' discussion is concerned primarily with the details of application of the analysis of gravity drainage presented in the paper to particular reservoir problems and secondarily to the effect of pressure maintenance on reservoir control indirectly through maintenance of desirable fluid properties. The first point regarding maximum rate of *segregation* is really a matter of definition. The analysis presented defines mathematically the *maximum* rate of *drainage* of oil from upstructure to downstructure regions due to the force of gravity.

Extension of the analysis to encompass the entire reservoir performance including effects of gravity, gas expansion, and imposed pressure gradients can be made theoretically by solving simultaneously Eq 1 for downdip oil flow, a similar relation for gas flow, and other relations involving the phase relation and material balance of oil and gas for assumed conditions of production and injection. This author once spent three months to no avail in an engineering committee attempt to make such an analysis including all of the factors. Afterward the simplified analysis presented in this paper was developed to provide a practicable simple method for determining whether a petroleum reservoir could be exploited by the gravity drainage method. Strictly speaking, Eq 3 applies only to point conditions within the reservoir where no gas is being released from solution in oil, but practically it defines gravity drainage in a reservoir where pressure is maintained constant by injection of gas into upstructure locations and where no free gas moves downstructure except to fill voids depleted of oil. In *all* cases it is the *maximum* rate at which oil can flow downdip by the force of gravity in regions of the reservoir where continuous phases of free gas and oil coexist.

Development of effective permeability to gas in a reservoir does not necessarily mean that gas will move upstructure while oil moves down. The direction of gas flow is controlled primarily by relative volumes of fluid withdrawal of upstructure and downstructure regions, by relative expansion of reservoir fluids in upstructure and downstructure regions, and by the relation of gravity forces to fluid-flow resistance. Thus it is entirely possible, say in the case of a gas cap or gas-saturated oil reservoir with upstructure wells shut in, that both oil and gas would flow downdip, even though gas were being released from solution in downstructure areas by release of pressure. It is equally possible, say in a case where high gas-oil-ratio wells upstructure were being produced, that flow of both gas and oil would be upstructure opposed to the action of gravity. Downdip drainage of oil would be greater if free gas were not migrating updip, provided effective permeability to oil were the same in both cases.

The second point of discussion concerning choice of effective permeability to oil is obvious. In Table 3 the comparison of "well" permeability from productivity indexes with "reservoir" permeability from regional movement of oil in the reservoir was intended to show only order of magnitude comparison as a check of the basic analysis. Inclusion of theoretical corrections for saturation gradients around the well bore, which rarely amount to more than 10 or 20 pct except in case of extreme pressure drawdown, would have added little to the comparison, since estimates of oil-drainage rate and pressure gradient were only rough approxima-

tions and coverage of the reservoir with productivity index tests was too incomplete to give a truly representative average.

The other Rocky Mountain field referred to by Mr. Jones contained oil originally undersaturated with gas. The comparison between "well" and "reservoir" permeabilities in both upstructure and downstructure regions was excellent before a free gas phase developed. "Reservoir" permeability was calculated using measured regional pressure gradients, liquid oil flow rates from material balance involving only measurement of production and expansion of undersaturated crude oil, and an approximate flow geometry.

When reservoir pressures in the upstructure area declined below the saturation pressure, productivity indexes declined sharply to 20 to 50 pct of their previous values—much greater decline than can be accounted for by using published relative permeability data. Interpretation of test data is not entirely unambiguous, however, because often linear extrapolation of data for bottom-hole pressure-production rate indicated static reservoir pressure 25 to 90 psi lower than the measured static pressure, even though the three flowing pressures were each within 5 to 10 psi of this straight line. Quite possibly this anomaly is due to simultaneous performance of two separate sand zones of quite different permeability, which are traceable at least over fairly wide areas. Reduction in calculated effective permeability is much less severe using the slope of the pressure-rate curves ignoring the measured static pressure. This latter "effective" permeability was not used in Mr. Jones' comparison.

A further weakness in the comparison of "well" and "reservoir" permeabilities in the area where free gas saturation had developed is that it involved determining oil-flow rate and pressure gradients in a strip about one 40-acre location wide around the structure. Oil-flow rates were based on volumetric balance of production, estimate of water encroachment, and expansion of liquid oil in the downstructure part of the reservoir. In our opinion, the region where reservoir pressure equaled the saturation pressure—a point fairly critical in the analysis—could not be determined well enough to define rates of flow underground satisfactorily.

When well-completion method and well handling directly affect local permeability conditions it is obvious that agreement will not exist between "well" permeability and "reservoir" permeability. However a carefully planned and carefully conducted program of core analysis, well testing, and reservoir analysis can usually provide a satisfactory answer within practical limits regarding the rate at which a petroleum reservoir can be produced by gravity drainage.

Regarding the last question of benefits of partial versus complete pressure maintenance by gas injection, it was exactly this question that prompted the analysis of the Lance Creek Sundance reservoir on which much of this paper was based. A point so often overlooked in planning a gas-injection, pressure-maintenance program is that it must be stopped some time. This analysis indicated that the pressure-maintenance program was restricting rate of production by the self-imposed plant capacity limit of gas production and by making ineffective those parts of the reservoir where permeability is too low to permit effective gravity drainage at economical rates. The operators therefore planned and have put into operation a program of depressuring the Unit Basal Sundance reservoir and storing the gas in the shallower depleted Dakota gas sand. The gas will be used for a final low-pressure gas drive of the reservoir, for fuel for field operations, or for such other needs as may develop.

This paper was limited to factual presentation of the past performance of the Lance Creek Sundance reservoir and to interpretation thereof with a minimum of conjecture of future performance. Since data are now available regarding early reaction of the reservoir to depressuring, it is being included in this discussion more as an indication of the information that will be developed within the next few years than as final conclusions.

In July 1947, when gas injection into the Unit area was about 6600 Mcf daily and oil production 2160 bbl daily, the average gross gas-oil ratio reached a peak of 5025 cu ft per barrel. Gas injection was gradually reduced till November 1947, during which no gas was injected. With an average oil production of 2122 bbl daily, the average gas-oil ratio had declined to 4150 cu ft per barrel with the same wells producing. Only once previously, in the latter part of 1943 and early part of 1944, had any similar reduction in gas-oil ratio been experienced—and that also occurred simultaneously with a substantial curtailment of gas injection.

A Critical Review of Methods Used in Estimation of Natural Gas Reserves

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(Tulsa and Los Angeles Meetings, October 1947)

Abstract

This paper discusses methods used in the estimation of natural gas reserves and the general conditions under which the various methods are applicable. The factors used in estimating natural gas reserves are reviewed. Errors which have been found to occur frequently are listed.

Introduction

The estimation of natural gas reserves has become of paramount interest because of the increasing importance of gas in the nation's economy. Gas is a most desirable fuel, a fact substantiated by the continued rise in the market demand. In addition, new uses for gas are being developed by the chemical, plastic, and associated industries, and plants are being built to make gasoline from natural gas. These are a few of the factors contributing to the importance of the nation's natural gas reserves.

With the increased importance of gas there is an increase in the need for reliable estimates of the magnitude and availability of natural gas reserves. These estimates are being used currently: (1) to determine which fields contain sufficient available reserves to justify the construction of pipe-line outlets to serve particular markets; (2) to design pipe lines necessary to serve those fields adequately; (3) to determine the location of industrial and chemical plants; (4) to finance the development of gas properties, and the construction of gas pipe lines; (5) to determine fair and adequate depletion allowances and depreciation rates; (6) to justify applications for gas pipe lines before various regulatory bodies; (7) to determine the number of wells required to exploit the reserves most economically; (8) to aid in establishing values for the purchase or sale of gas properties, and for purposes of inheritance taxes; (9) to determine equities under unitized operations; (10) to provide a basis for calculating the economics of gas-cycling operations.

History of Estimation of Natural Gas Reserves

The natural gas industry in the United States had its beginning during 1826 when natural gas was used for lighting the city of Fredonia, N. Y. The first natural gas pipe line was a 25-mile wooden line constructed from hollowed logs, connecting West Bloomfield and Rochester, N. Y. There is no record of an attempt to estimate the gas reserve at West Bloomfield but an attempt was made to determine the capacity of the well by measuring the time required to fill a large balloon.

One of the earlier publications concerning estimation of natural gas reserves is the "Manual for the Oil and Gas Industry," published by the Treasury Department, United States Internal Revenue, in 1919. The following methods of computing "gas depletion" are listed: (1) production decline of the gas well or property; (2) decline in open-flow capacity; (3) comparison with the life history of similar wells or properties, particularly those exhausted

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or nearing exhaustion; (4) size of the reservoir and pressure of gas, or pore-space method; (5) other indications, such as the decline in minute pressure (minute pressure is the pressure recorded at the wellhead after the well has been closed for one minute), or the appearance of oil or water in the well or neighboring wells, were listed as being significant indications of the length of life of a gas well.

Also in 1919, E. W. Shaw published a discussion of the estimation of gas reserves entitled "Principles of Natural Gas Land Valuation." He lists the following methods: (1) pore-space method, based on the size of the reservoir and the pressure of the gas; (2) past production compared with (*a*) rock-pressure decline, (*b*) capacity decline, and (*c*) line delivery decline; (3) production curve where production has been maximum and controlling conditions uniform, (4) comparison with performance records of the wells and tracts that are comparable.

In 1922, Ruedemann and Gardescu published an article entitled "Estimation of Reserves of Natural Gas Wells by Relationship of Production to Closed Pressure." They say that three types of well tests were then being used to determine the value of gas wells; namely, open-flow capacity, closed pressure, and minute pressure above the line. Open-flow tests were not usually available, and the fact that line pressure varied considerably made the use of the minute-pressure-above-the-line method precarious. The general method then in use, and also the method advocated by the Internal Revenue Bureau, was the method of constant production to pound decline. Ruedemann and Gardescu criticized this method, and advocated what they called the area method. The main theme of their paper was "to show that the area corresponding to a closed pressure decline is proportionate to the amount of gas produced, and that volume is not proportionate to the decline in closed pressure." The area referred to above is the area under the curve of closed pressure plotted against time.

Roswell H. Johnson and L. C. Morgan published an article in 1926 entitled "Critical Examination of Equal Pound Loss Method of Estimating Gas Reserves," in which they said that the most accurate method of gas-reserve estimation is to extrapolate a curve of production per pound drop plotted against time.

In 1928, J. Versluys, in "An Investigation of the Problem of the Estimation of Gas Reserves," suggested a method of volumetric estimation when the thickness and porosity of the producing formation are not known. The method consists of observing pressures in closed-in wells while flowing a central well at various rates. By use of the calculus and curves of plotted test data, a value for the factor of porosity times thickness can be obtained. However, the areal extent of the reservoir must be estimated by other methods before the reserve can be calculated.

In 1935, Dr. E. A. Stephenson published an article on Valuation of Natural Gas Properties. He lists the commonest methods of estimating gas reserves as: (1) the porosity-pressure method, (2) the rock-pressure, production-decline method, and (3) miscellaneous methods, such as comparison with other gas fields and indications of open-flow capacity. He also points out the necessity for using isobaric maps in obtaining the average field pressure rather than an arithmetical average of individual well pressures. Stephenson says that, "Failure of Johnson and Morgan to recognize this fact led to entirely erroneous conclusions as to the merits of the equal-pound-loss-in-pressure method of estimating reserves."

The many criticisms of the equal-pound-loss method by early writers indicate failure of the method in many instances. These failures seem to be attributable to two causes: (1) presence of a water drive, in which case the method is inapplicable,

or (2) use of arithmetic average well-head pressures in incompletely developed reservoirs.

Present Methods of Estimating Natural Gas Reserves

Gas-reserve estimators currently use the same general methods described by the early authors with the addition of certain refinements made possible by the greater amount of data obtained on gas reservoirs, and the increased knowledge of reservoir mechanics.

The terms currently used by the American Gas Association to describe the various types of gas in accordance with the nature of its existence in the reservoir are defined as:

1. Nonassociated gas; i.e., free gas not in contact with crude oil in the reservoir.
2. Associated gas; i.e., free gas in contact with crude oil in the reservoir.
3. Dissolved gas; i.e., gas in solution in crude oil in the reservoir.

Methods of Estimating Nonassociated Gas Reserves

Volumetric Method

The volumetric method, as currently used, makes use of structural and isopachous maps based on data from electrical logs, cores, and drill-stem and production tests. Sand volumes are obtained by planimetering. Core-analysis data and interpretation of electrical logs permit reasonable estimates of porosity, connate water, and net productive thickness, so that the volume of gas-filled pore space may be calculated. Laboratory analysis of the gas for determination of its compressibility at various pressures and temperatures, and the determination of reservoir pressure and temperature by recording instruments, make it possible to calculate the volume of gas contained in the reservoir with reasonable accuracy.

Calculation of the gas in place in the reservoir may be accomplished by use of the following formula:

$$Q = 43{,}560 \times \phi \times (1 - S_w) \times \frac{P}{P_b} \times \frac{460 + t_b}{460 + t} \times \frac{1}{Z}$$

where Q = cubic feet gas per acre-foot at base temperature and pressure.
43,560 = number of cubic feet per acre-foot.
ϕ = porosity expressed as a decimal fraction.
S_w = interstitial water expressed as a decimal fraction.
P = reservoir pressure, psia.
P_b = base pressure, psia.
t = reservoir temperature, deg F.
t_b = base temperature, deg F.
Z = compressibility factor at pressure P.

Reserves may also be calculated volumetrically by use of the pound-mol as a base for computation. The following formula is used

$$V = \frac{ZNRT}{P}$$

where V = volume in cubic feet.
Z = compressibility factor at pressure P.
N = number of pound-mols.
R = 10.71.
T = absolute temperature.
P = pressure, psia.

The volume occupied by one pound-mol of an ideal gas at standard conditions (60°F and 30 in. of mercury) is 379.4 cu ft, therefore the volumetric formula may be expressed as follows:

$$Q = 43{,}560 \times \phi \times (1 - S_w) \times \frac{379.4}{V}$$

where V = cubic feet gas per pound-mol at reservoir conditions.

If a water drive is not anticipated, the volume of gas that will remain in the reservoir at the expected abandonment pressure may be calculated and deducted from the volume of gas initially in place, to deter-

mine the volume of recoverable gas. The abandonment pressure to be used depends on the price of gas, the productivity indexes of the wells, the size of the field, its location with respect to market and the type of market. If the market is a transmission pipe line, the operating pressure of the line may be a controlling factor in the abandonment pressure for small fields, but for large fields installation of compressor plants may be economically feasible, thus lowering the abandonment pressure substantially below the operating pressure of pipe lines serving the area.

In water-drive fields, the pressure will be wholly or partially maintained by the movement of water into the reservoir as gas is withdrawn, the magnitude of pressure decline being dependent on the rate of gas withdrawal with respect to the rate of water advancement.

Water advancement rate is a function of the area of the gas-water contact, the permeability of the reservoir, and the pressure differential created by gas withdrawals. Recoverable gas usually is estimated for water-drive reservoirs by applying a recovery factor to the calculated volume in place. The selection of a recovery factor depends on the thickness and homogeneity of the sand, the relative permeability of the sand to gas and water at varying gas saturations, the percentage of the gas-containing portion of the reservoir originally underlain by water, the dip of the reservoir beds, and the amount of structural closure above the gas-water contact. The recovery factor will be highest when the sand is uniform and homogeneous, the permeability of the sand to gas is high at low gas saturation, the percentage of the gas-containing portion of the reservoir originally underlain by water is relatively small, the beds are relatively steep, and the amount of structural closure above the gas-water contact is large.

Recovery factors used by different estimators under the same conditions vary widely. Study of the recovery from depleted fields for which volumetric data are available is helpful in selecting a recovery factor.

The volume of gas in place per acre-foot may be computed at any stage of depletion at which the reservoir pressure is known. If the volume of gas that has been withdrawn from the reservoir is also known, the following formula may be used to determine the volume of the reservoir if a water drive is not operative:

$$A = \frac{C}{Q_o - Q}$$

where A = acre-feet gas pay.
C = cumulative gas production in cubic feet to reservoir pressure P.
Q_o = cubic feet gas initially in place per acre-foot.
Q = cubic feet gas in place per acre-foot at reservoir pressure P.

If this calculation is made at various reservoir pressures and the reservoir volume is indicated to be the same by each calculation, the absence of water drive is indicated.

If water is encroaching into the reservoir, this calculation will result in an apparent increase in the number of acre-feet in the reservoir at each successive time. When this condition is encountered it is necessary to rely solely on geologic data to determine the reservoir volume. Successively larger reservoir volumes might also be calculated for gas fields when water drive is absent if only a small part of the reservoir is developed and shut-in pressures measured in the wells are considerably below the true pressure of the reservoir. Then, as additional wells are drilled, the calculated average pressure approaches the true pressure of the reservoir.

Discussion of the Factors in the Volumetric Formula

The porosity of cores can be measured with a high degree of accuracy, but even if

all wells are cored only a minute fraction of the reservoir volume is sampled. For this reason the estimation of porosity is especially hazardous for limestone formations and for some erratic sandstones in which cementation or argillaceous material cause rapid porosity variations. However, many producing sands have sufficient homogeneity so that the porosity can be estimated with a fair degree of accuracy.

Estimates of gas reserves must often be made for reservoirs for which no cores have been analyzed. In such cases porosity can be estimated from a general knowledge of the formation based on data from other fields.

Porosity is the most important factor in the volumetric formula and a small error in porosity will result in a large error in the estimated reserve. For instance, if the porosity is actually 20 pct and is estimated to be 15 pct, the result is a reserve estimate 25 pct low. (Fig 2 shows the relationship of the original volume of gas in place to the depth of the reservoir for various net porosities.)

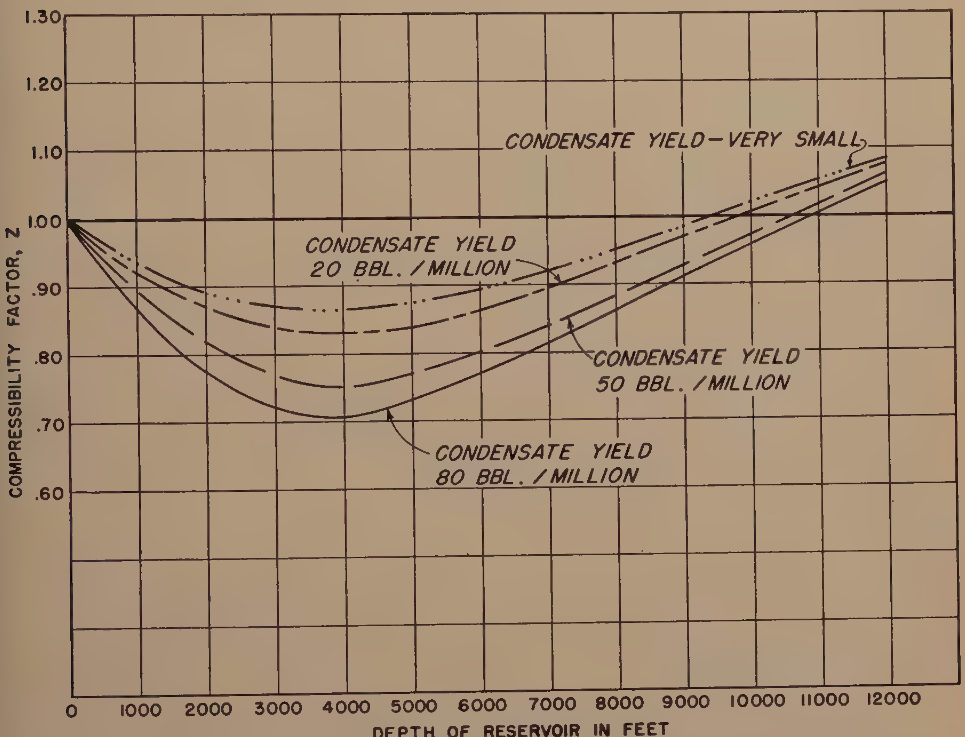

FIG 1—CHANGE IN COMPRESSIBILITY FACTOR WITH DEPTH, AND COMPOSITION OF WET GAS.

The connate water is a factor that must often be estimated, since laboratory determinations are not always available. Use of restored state, or capillary pressure, methods is resulting in more and better information on connate water than has been available in the past. Connate water became generally used as a factor in the volumetric formula in about 1936, following studies by Horner, Lewis, Schilthuis, Pyle, Jones, and others.

In many instances use of the electrical log to estimate connate water will give satisfactory results by Archie's method, Guyod's method, or the resistivity-departure-curve method.

Pressure and temperatures usually are obtained by measurement but if measurements are not available fairly accurate estimates can be made from the known rate of pressure and temperature increase with depth in the area.

The compressibility factor can be determined accurately by laboratory measurement. If laboratory measurements are not available reasonable estimates can be made by the use of published data. This factor is sometimes ignored by estimators although an error of as much as 30 pct may result from its omission. This factor is especially large for gases rich in condensate and occurring at depths of 3500 to 4500 ft, in which case its omission results in underestimation of the reserve (see Fig 1). Omission of this factor leads to overestimation of the reserve in abnormally high-pressured reservoirs frequently encountered below 10,000 ft in some areas of the Gulf Coast.

In calculating the compressibility factor at abandonment pressure, the estimator should consider changes in the composition of the gas which will occur as a result of cycling or retrograde condensation.

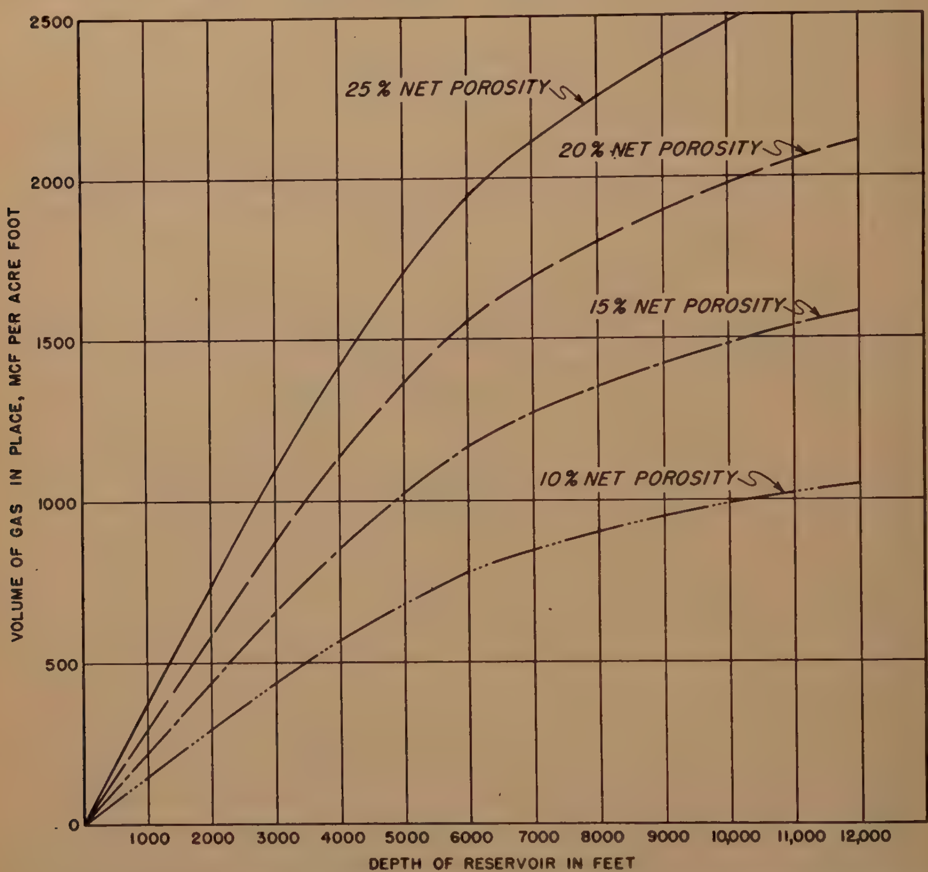

FIG 2—RELATION OF ORIGINAL VOLUME OF GAS IN PLACE PER ACRE-FOOT TO DEPTH OF RESERVOIR FOR VARIOUS NET POROSITIES.

Base pressure, 14.65 psi; gravity of wet gas, 0.678.
Separator yield, 20 bbl per million cubic feet gas.

The authors' experience in checking estimates made by themselves and others indicates that the greatest errors in volumetric calculations are usually the result of incorrect determinations of net productive thickness.

Usually the thickness is underestimated in sands interbedded with shale unless all wells have been cored with a high percentage of recovery and careful description has been made of the cores, as productive layers less than one foot thick, which are not indicated by the electric log, may comprise a large portion of the reservoir.

On the other hand, net productive thickness can easily be overestimated for indurated sandstones such as the Travis Peak formation (Hosston) of Lower Cretaceous age in East Texas and North Louisiana and the Wilcox formation of Eocene age in South Texas. The authors are familiar with several instances in which the estimates by various engineers differed by several hundred per cent as a result of differences in estimating the net productive thickness of formations of this type. Net productive thickness also can be overestimated in limestone or dolomite reservoirs because of the occurrence of dense streaks in the reservoir rock.

Aids in properly estimating the net productive thickness are cores, drilling-time logs, radioactivity logs, and measurement of gas increases while drilling with cable tools. In many cases sufficient data are not obtained to make a reliable volumetric estimate of reserves in limestone and indurated sandstone reservoirs.

Estimates of reserves in new or incompletely developed fields may vary widely because of errors in estimating the areal extent of production. To minimize these errors, subsurface data should be supplemented by geophysical data whenever possible.

The pressure bases ordinarily used vary from 14.4 to 16.7 psi. The estimator should be careful to indicate clearly the pressure base at which the reserves are stated. Reserves stated at a base of 14.4 psi will be approximately 16 pct greater than the same reserves stated at a base of 16.7 psi. The base temperature ordinarily is 60°F.

The accuracy of the factors used in the volumetric formula by an estimator for any particular reserve calculation depends on the amount of data available, and the experience and judgment of the estimator.

The importance of experience and judgment may be illustrated by an estimate made by H. W. Bell and R. A. Cattell, U. S. Bureau of Mines, in July 1921. They estimated the gas reserve of the Monroe gas field, in northeast Louisiana, by the volumetric method. This field produces from a chalk formation of Upper Cretaceous age at a depth of 2000 to 2300 ft. Although the limits of the field had not been defined, the thickness of the gas rock was extremely variable and data regarding rock pressure were few, their estimate of the gas in place differs by only 15 pct from current estimates made with the benefit of 26 years additional performance data.

The Decline-curve Method

The pressure-decline curve is one of the most widely used, and one of the most reliable, of the several means of estimating gas reserves in reservoirs that do not have a water drive. Several types of pressure-decline curves are used. One or more of these curves should be constructed for each reservoir studied to determine whether a water drive is present and, if so, its relative importance.

Early pressure-decline curves were constructed from closed-in wellhead pressures, sometimes referred to as "rock pressures." Since the development of methods of measuring and calculating reservoir pressures, most engineers and geologists use reservoir pressures in plotting decline curves.

If a water drive is not present, wellhead or reservoir pressure plotted against cumu-

lative production may be extrapolated in a straight line to the expected abandonment pressure and the ultimate recovery can be read direct. Estimates made in this manner ignore the effect of deviation from Boyle's law.

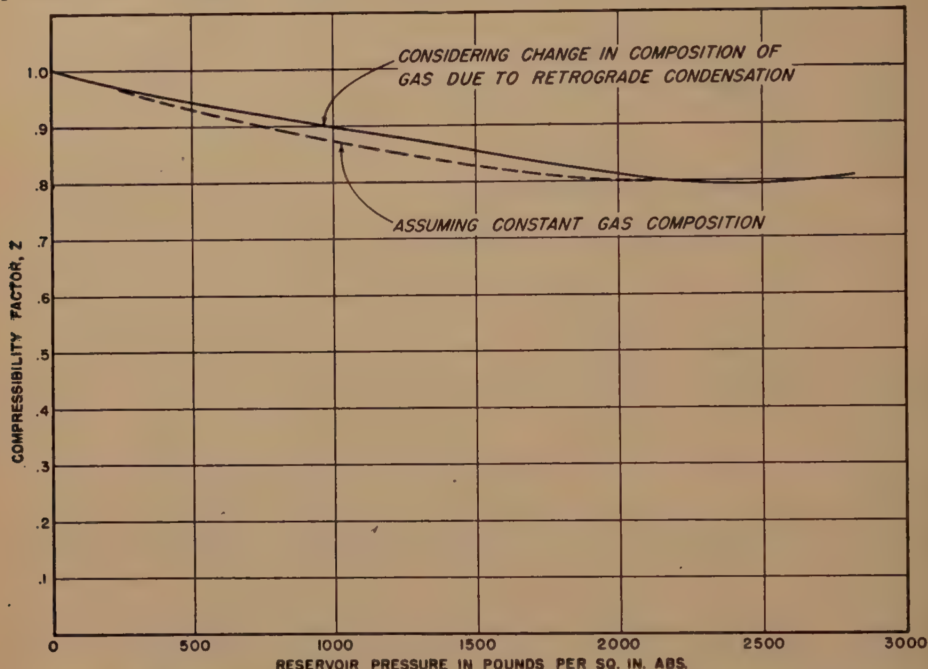

FIG 3—VARIATION OF COMPRESSIBILITY FACTOR Z WITH PRODUCTION AT RESERVOIR TEMPERATURE OF 188°F, FOR A WET GAS HAVING INITIAL GRAVITY OF 0.812.

When the accuracy of other data justify refinements, reservoir pressure divided by the compressibility factor Z may be plotted against cumulative production to correct for the effect of deviation from Boyle's law (see Fig 3 and 4).

The equal-pound-loss method is a special use of this method in which a curve is not actually constructed, but the production at the point of intersection of the curve with the abandonment pressure is calculated by assuming a constant slope determined by the initial pressure and the pressure after a known volume of gas has been withdrawn. This method is not as reliable as a decline curve, since only two pressure points are used.

The equal-pound-loss method may be corrected for deviation of gas from Boyle's law by use of the following formula, published by Dr. E. A. Stephenson in the "Geology of Natural Gas" in 1935:

$$R = Q\frac{(P_r d_r - P_a d_a)}{(P_i d_i - P_r d_r)}$$

where R = gas reserve to abandonment pressure.

Q = production of reservoir during decline in pressure from P_i to P_r.

P_i = initial pressure of reservoir.

P_r = reservoir pressure as of date of appraisal.

P_a = reservoir pressure as of date of abandonment.

d_i = deviation factor at P_i.

d_r = deviation factor at P_r.

d_a = deviation factor at P_a.

Cumulative pressure drop may be plotted against cumulative production on

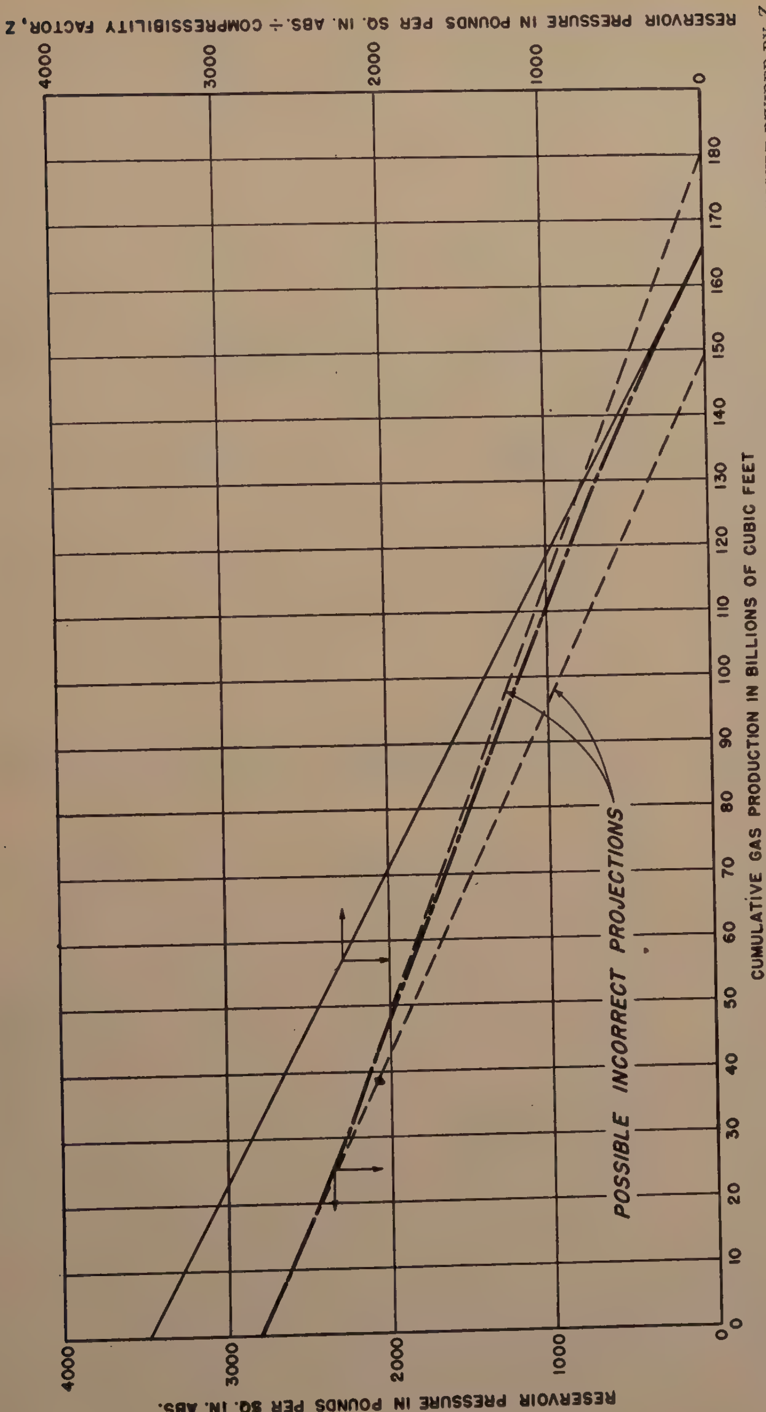

FIG 4—COMPARISON OF THEORETICAL RESERVOIR PRESSURE VS CUMULATIVE PRODUCTION AND THEORETICAL RESERVOIR PRESSURE DIVIDED BY Z VS CUMULATIVE PRODUCTION.

logarithmic paper. This method of plotting was developed by H. C. Miller, of the U. S. Bureau of Mines. If cumulative production per pound drop is constant, the curve will be a straight line with a slope of 1 (45° angle with the horizontal). If water, oil or gas is encroaching into the known gas area, the slope will be less than 1 (an angle of less than 45° with the horizontal). The effect of deviation from Boyle's law will cause a slight flattening of the curve as illustrated in Fig 6. If this curve has a slope of 1, or slightly less, the ultimate production may be determined by extrapolating the curve to a pressure drop equivalent to the initial pressure minus the expected abandonment pressure.

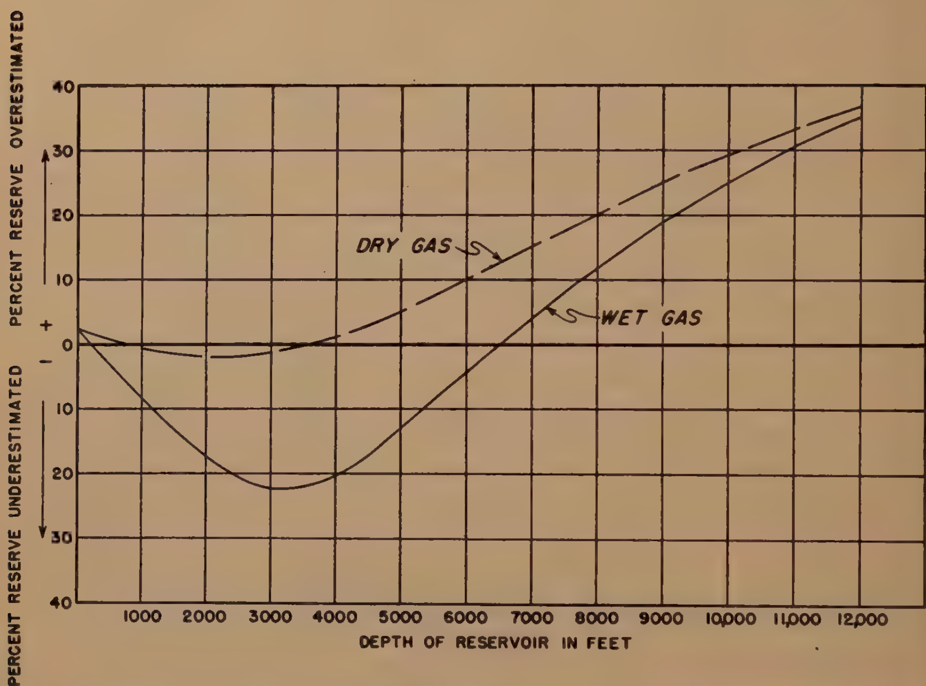

FIG 5—PERCENTAGE OF ERROR RESULTING FROM OMISSION OF BOTH TEMPERATURE AND COMPRESSIBILITY FACTORS.

Cumulative production per pound decline in closed-in wellhead or reservoir pressure may be plotted against cumulative production or against time. If values for cumulative production per pound pressure decline are constant, the resulting curve is a straight line parallel to the time or cumulative production axis, and it may be assumed that estimates of reserves made by use of the equal-pound-loss method or by extrapolation of the pressure-cumulative-production-decline curve will be correct. If the slope of the curve is negative (i.e., values of cumulative production per pound drop increase with cumulative production or time) water, oil or gas is encroaching into the known gas area. It should be remembered that the effect of deviation from Boyle's law will cause a slight increase in values even if a water drive is not present. This effect is shown on Fig 7.

A large error is often introduced by the method of obtaining the average field pressure. If numerical averages of the producing wells are used for each point plotted, the rate of drilling influences the slope of the curve. If only a few wells are

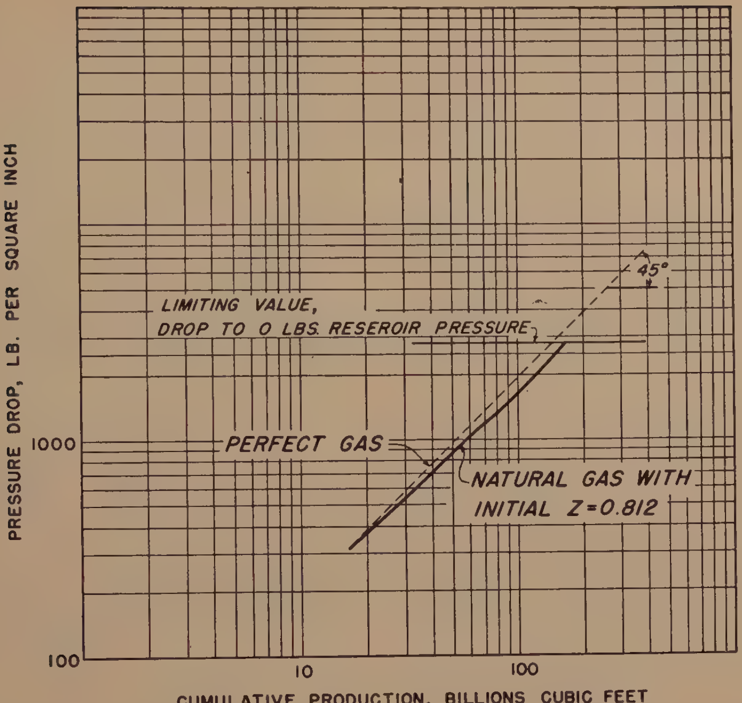

FIG 6—THEORETICAL CURVE, PRESSURE DROP VS CUMULATIVE PRODUCTION FOR CONSTANT-VOLUME RESERVOIR. INITIAL BOTTOM-HOLE PRESSURE, 2815 POUNDS PER SQUARE INCH.

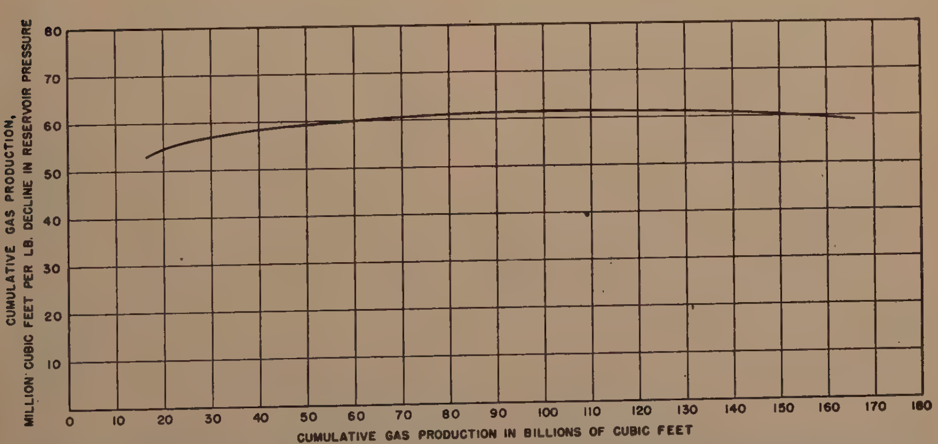

FIG 7—RELATION OF CUMULATIVE GAS PRODUCTION PER POUND DECLINE IN RESERVOIR PRESSURE VS CUMULATIVE GAS PRODUCTION FOR RESERVOIR WITH 166.34 BILLION CUBIC FEET GAS IN PLACE. INITIAL Z, 0.812.

drilled in a large reservoir of low permeability, the numerical average of their pressures after considerable gas has been withdrawn may be considerably lower than the average pressure of the reservoir. If the drilling rate is rapid enough with respect to permeability of the reservoir and rate of gas withdrawal, new wells may be completed with closed-in pressures considerably higher than the closed-in pressures of wells already producing. The effect of this is a flattening or a reversal of slope of the cumulative production-pressure-decline curve.

Errors of this type can be reduced by constructing isobaric maps and planimetering to obtain the weighted average pressure. The reservoir area used in obtaining the weighted average pressure should be the same for each point plotted. If a reservoir is determined to be larger than previously estimated, all isobaric maps should be corrected and pressures recalculated so that all points on the curve represent the average pressure of the same area. Greater accuracy can be obtained by weighting pressures on the basis of reservoir pore volume rather than on the basis of surface acreage, if there are large variations in net productive thickness.

Methods of Estimating Associated Gas Reserves

Certain additional problems are encountered in estimating associated gas reserves. First, the volume of gas that may be produced from the gas cap may exceed the original volume of gas contained in the gas cap because of migration of solution gas upstructure, with reduction of pressure on the oil zone. Second, the reservoir volume occupied by the gas cap may increase as oil is withdrawn or it may decrease because of movement of oil upstructure. Third, the volume of gas produced from the gas cap may not be known accurately because some oil wells near the gas-oil contact may produce associated gas as well as dissolved gas.

Decline-curve methods for estimating the amount of gas remaining in a gas cap are inaccurate since the volume of the reservoir will remain constant only under exceptional conditions and dissolved gas may migrate into the gas cap.

The problem of estimation is simplified if no effort is made to distinguish between associated and dissolved gas. The total original gas reserve may be computed and the cumulative production of associated and dissolved gas subtracted to obtain the total gas reserve remaining at any time.

Methods of Estimating Dissolved Gas Reserves

The principal method of estimating dissolved gas reserves is volumetric. The original gas in place is determined by estimating the original volume of stock-tank oil in place, and multiplying this value by the original solution gas-oil ratio. The recovery factor to be applied depends on the mechanics under which the reservoir will be produced.

Water Drive

For reservoirs in which the pressure does not drop below the bubble point, the gas-oil ratio will be constant and the recovery factor for gas will be the same as the recovery factor for oil. The East Texas field is an example of this type of reservoir.

For reservoirs in which the pressure drops below the bubble point, the recovery factor for gas will be greater than the recovery factor for oil. In order to make an accurate determination of the recovery factor, it is necessary to predetermine the pressure history of the field by material-balance and water-influx calculations, or by extrapolating a curve of pressure against cumulative production, if rates of production have been constant. After the pressure history of the field has been estimated the amount of gas to be recovered can be reasonably approximated by multiplying the volume of recoverable oil by the original

dissolved gas-oil ratio and adding an amount equal to the volume of unrecoverable oil times the difference in the original dissolved gas-oil ratio and the amount of gas in solution per barrel of oil at the average pressures at which the reservoir is expected to be produced.

Constant-volume Type Reservoir

To calculate the amount of recoverable gas, it is necessary to calculate the gas originally in place and subtract the gas that is calculated to be unrecoverable at the expected abandonment pressure of the reservoir. This may be calculated by the following equations:

$$R = O_pG_o - U$$

where R = recoverable gas, cu ft.
U = unrecoverable gas, cu ft.

$$\text{or } (V - O_uFv_a)5.61 \frac{(P_a)}{(P_b)} \frac{(520)}{(t + 460)} \frac{(1)}{(Z_a)} + O_uG_a$$

where V = void space in reservoir, bbl, or $7758 \times \phi \times (1 - S_w)$.
O_u = unrecoverable oil, bbl, at stock-tank conditions, or $(O_p - O_r)$.
O_p = original oil in place, bbl, at stock-tank conditions, or $\frac{V}{Fv_o}$.
O_r = recoverable oil, bbl, at stock-tank conditions.
Fv_o = original formation volume factor.
P_a = reservoir pressure at abandonment, psia.
P_b = base pressure, psia.
t = reservoir temperature, deg F.
Z_a = compressibility factor at P_a.
G_a = cubic feet gas (measured at base pressure) in solution per barrel stock-tank oil at P_a.
G_o = cubic feet gas (measured at base pressure) originally in solution per barrel oil at stock-tank conditions.

Common Errors in Method of Estimating Natural Gas Reserves

The following errors have been noted in reviewing gas-reserve estimations:

1. Construction of a pressure curve for an early well in a field and application of the indicated reserve to later wells on a per well or per acre basis.
2. Construction of pressure-decline curves from arithmetic average pressures when well spacing is not uniform and the number of wells is not constant.
3. Construction of pressure-decline curves using pressures obtained from isobaric maps, all of which do not cover the same area.
4. Failure to check decline-curve estimates by volumetric calculations to determine whether the area, thickness, and porosity required to contain the estimated reserve conflict with the available data.
5. Failure to consider the effect of deviation from Boyle's law.
6. Assuming that neglect of corrections for temperature and compressibility are compensating (see Fig 5).

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DISCUSSION

J. J. Arps*—I would like to invite the authors' attention to API Paper No. 801-20A and ask them to make some references to the effect of solubility of petroleum gases in brines both with regard to recovery estimates and producing characteristics of gas reservoirs. Some refinements may be indicated where the accuracy of the estimates would appear to justify taking these factors into account.

In water-drive gas fields I wonder if anyone has attempted gas recovery estimates based on the rate of increase in water production expressed, for instance, in barrels of water per million cubic feet, plotted against cumulative gas production. No mention is made of such a method in this paper.

* British American Oil Producing Co., Tulsa, Okla.

G. B. Moody*—The authors have presented an excellent summary of methods used in estimating natural gas reserves. They have discussed the limitations of the various methods and have indicated the need for careful scrutiny of data by the estimator prior to his choice of values for the parameters employed in any calculation. Fig 1–7 are clear and interesting. The following comments are presented for the consideration of the authors.

1. Inclusion of computations by each method from actual data probably would add to the value of such a review especially for those not actively engaged in estimating gas reserves.

2. The factors influencing the selection of the abandonment pressure to be used might include P.I.'s, which have considerable bearing on the economic abandonment pressure in many pools.

3. Inclusion of the equation for calculating the pressure due to the weight of the gas column, in order to determine reservoir pressure from measured casinghead pressure, would be of value.

4. The authors' conclusion following the equation, $A = \dfrac{C}{Q_o - Q}$ is: "If this calculation is made at various reservoir pressures and the reservoir volume is indicated to be the same by each calculation, the absence of water drive is established." This conclusion has been accepted generally but is not necessarily valid. Several months ago a member of our Reserves Staff, J. E. Lindsay, found that the absence of water drive was not established in spite of the fact that his calculations at various reservoir pressures indicated constant reservoir volume. A comparison of the authors' equation with a similar one which includes a term for water encroachment and further comparison of the values for A calculated from the two equations and using identical values for C, Q_o and Q in both equations will demonstrate this point.

The authors' equation: $$A = \frac{C}{Q_o - Q} \qquad [1]$$

where

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A = acre-feet gas pay
C = cumulative gas production in cubic feet to reservoir pressure P
Q_o = cubic feet gas, measured at standard conditions, initially in place per acre foot
Q = cubic feet gas, measured at standard conditions, in place per acre-foot at reservoir pressure P

This equation ignores water encroachment, but may be rewritten to include water encroachment as follows:

Let F = percentage of original gas pool, expressed as decimal, that has been occupied by encroaching water when pressure is P.

Then:

$$C = AQ_o - (1 - F)AQ$$
$$= A\,[Q_o - (1 - F)Q] \text{ or}$$
$$A = \frac{C}{Q_o - (1 - F)Q} \qquad [2]$$

consider a gas pool with parameters:

Average depth to mid-point of gas pool: 5250 ft

Initial shut-in casinghead pressure (P_o): 2100 psia

Initial temperature at mid-point of gas pool: 155°F

Specific gravity of gas: 0.568

H. J. Gruy and J. A. Crichton (authors' reply)—With reference to Mr. Arps' comments regarding the effect of the solubility of petroleum gases in brines on recovery estimates and producing characteristics of gas reservoirs, the presence of gas dissolved in the edge water will result in more reserves than estimated by the volumetric method. However, it is our opinion that the effect will be appreciable only when large volumes of water are produced.

With reference to Mr. Arps' comments regarding estimation of gas reserves by plotting barrels of water per million cubic feet against cumulative gas production, it appears that this method might be useful under conditions in which large volumes of water are removed from the wells at frequent intervals. However, we have never used this method.

With reference to Mr. Moody's statement that "the factors influencing the selection of the abandonment pressure to be used include P.I.'s., which have considerable bearing on the economic abandonment pressure in many pools," we are in accord. Productivity indexes can be readily calculated from back pressure tests of the wells, which are usually available.

We are particularly grateful to Mr. Moody for his comments regarding conditions under

Table 1

Time	1 P, Psia	2 P_r Psia	3 C, Mcf	4 Q Cu ft per Acre-feet	5 From Eq 1 $A = \frac{C}{Q_o - Q}$ Acre-Feet	6 F, Per Cent	7 From Eq 2 $A = \frac{C}{Q_o - (1 - F)Q}$ Acre-Feet
T_0	2,100	2,225	0	6,643,000		0	
T_1	1,900	2,010	19,661,000	5,990,000	30,100	2.0	25,400
T_2	1,600	1,695	49,546,000	4,996,000	30,100	6.1	25,400
T_3	1,400	1,480	69,600,000	4,330,000	30,100	9.9	25,400
T_4	1,150	1,217	95,056,000	3,485,000	30,100	16.8	25,400

The constant volume A in column 5, Table 1, is calculated from eq 1 using successive determinations of P, C, and Q. The constant volume A in column 7, Table 1, is calculated from eq 2 using the same successive values of P, C, and Q, and the indicated values of F. Note that disregard of water encroachment (eq 1) gives an indicated volume of the gas pool that is 18.5 pct greater than the true volume as calculated from eq 2.

The conclusion is that absence of water drive is not established even though constant reservoir volume is indicated by solution of the authors' equation at various reservoir pressures.

which the equation, $A = \frac{C}{Q_o - Q}$ will give constant values for A even when water is encroaching into the reservoir. One of the characteristics of a water-drive reservoir is that the pressure at any time is a function of the rate of withdrawal and the effect of all previous rates of withdrawal. Therefore, with certain changes in production rates between pressure points the conditions described by Mr. Moody may be obtained. In our opinion it is improbable that these circumstances will continue over any appreciable portion of the life of the reservoir, even under conditions of limited water drive.

Waters of Producing Fields in the Rocky Mountain Region

By James G. Crawford,* Member AIME

(Denver Meeting, September 1947)

Abstract

Correlation of water with its reservoir zone or formation has been one of the applications of oil-field water analysis of greatest direct value to the petroleum engineer. The water in each producing zone tends to have diagnostic characteristics by which it can be distinguished from every other water above or below that zone in that immediate vicinity. Representative analyses of oil-field waters from producing oil and gas fields in the Rocky Mountain region are included, and the diagnostic characteristics are discussed briefly. It is concluded that the generally dilute nature of Rocky Mountain oil-field waters is a result of dilution by meteoric waters, and that there is no relationship between presence or absence of commercial oil and the character of water in a structure.

Introduction

The study of waters associated with oil and gas began more than 50 years ago and has been well recognized by operators, engineers, and geologists for about 30 years. It appears unnecessary at this time to recite the history of oil-field water analysis; suffice to say that it has proved its worth many times to the production engineer suddenly confronted with water problems in producing oil and gas wells.

Chemists and geologists have studied the possible origin of these waters and as yet the subject is unsolved in many important phases. There are both local and regional problems connected with the explanation of concentrations and characteristics peculiar to each field, each subsurface zone and each province. Criteria useful in postulating the occurrence of oil or gas in one province completely fail when applied to another, and data carefully prepared and analyzed from one field may be actually misleading when applied to another.

Correlation of water with its reservoir zone or formation has been one of the applications of oil-field water analysis of greatest direct value to the engineer. The concentrations and characteristics of the waters are essential to the engineers and geologists making interpretations of electric logs in this region. The behavior of water under conditions of reservoir temperature and pressure is dependent to a great degree upon its concentration and characteristics, and thus important to the reservoir engineer. With the advent of secondary recovery methods in the Rocky Mountain region the characteristics and treatment of water will become increasingly important.

Premises upon which Correlation Is Based

A brief review of the geochemical history of oil-field waters will suffice to present the premises upon which correlations of the waters are based. Sedimentary rocks which are now stratified were first sediments in seas, lakes and streams. These sediments were filled interstitially with connate water. With burial the sediments were compressed and consolidated, integrated and indurated into bed rock and much of the connate water was dispelled. Following the formation of bed rock the strata were sub-

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jected to many changes, such as very deep burial at zones of moderately high temperatures, and tilting and uplifting with erosion along exposed scarps, valleys and canyons. Exposed, eroded porous strata were invaded by ground water of meteoric origin whereby connate water has been displaced and diluted. Contiguous to deeply incised streams under conditions of arid climate the ground water may have been lowered whereby connate water was eliminated from strata several thousand feet thick. These geologic and geochemical changes were slow and gradual over millions of years. As a result the composition of water from a given zone appears very nearly constant throughout the economic life of an oil or gas field. The amount of connate water in a given bed and the amount of interstitial water subsequently migrated into a given bed provide the concentrations and characteristics peculiar to each locality or geological province.

The wide range in connate waters can be shown by reciting that some brines in oil fields of other regions have concentrations nine times that of normal sea water of 35,000 ppm total solids. In the Rocky Mountain region the greatest concentration in producing fields is 100,000 to 150,000 ppm occurring in the Weber sand at Rangely; the most dilute is 200 ppm total solids in the Tensleep sand at Dallas, Derby, Lander and Black Mountain. The concentration and chemical characteristics of a connate water may be more nearly its original properties than has often been considered in earlier studies. The sea water may have been modified by meteoric waters at the time deposition was occurring. Thus, variations in oil-field waters do not always indicate alterations subsequent to origin, and low concentration does not always indicate hydraulic flushing or ground water infiltration.

The important point is that water contained in each producing zone tends to have diagnostic characteristics by which it can be distinguished from every other water above or below that zone in that immediate vicinity. The soundness of the premise is attested by the experience of the author who has not found a violation in more than 18 years' work of correlating waters in the Rocky Mountain region.

Alterations Subsequent to Entrapment

It is doubtful if there has been appreciable change in chemical characteristics of water trapped in structures devoid of hydrocarbons. It is assumed that ground waters cannot infiltrate to any extent and that chemical changes after accumulation are negligible. In structures containing oil or gas, though, a different picture is presented. Connate water has had the opportunity of reacting with hydrocarbons and there is no doubt that alteration has occurred in many instances. The reactions between hydrocarbons and different types of water are not thoroughly understood, but it is very well established that sulphate reduction, under certain conditions, does take place. The equation involving this reaction is

$$Na_2SO_4 + 2C = Na_2S + 2CO_2$$

It is thought that the reaction is aided or initiated by anaerobic bacteria. The products of the reaction are both chemically active; the sulphides may be precipitated from the solution as metallic salts and become part of the strata; the carbon dioxide may escape as a gas, or become fixed in the aqueous solution as a bicarbonate. Presumably this reaction would result in a water containing little, if any, sulphate and an excess of bicarbonate.

The occurrence of hydrogen sulphide in the oils and waters of pre-Triassic strata is striking. These waters occur in, or contact, limestone beds and are for the most part sulphate waters. It is believed that association with hydrocarbons has resulted in partial reduction of the sulphates in the water, and the fact that the oil and water both contain hydrogen sulphide gas is some

evidence that active reduction is occurring at the present time. It is noticeable that waters of these older formations in barren structures often carry small to moderate amounts of hydrogen sulphide, the reduction being accomplished by carbonaceous matter in the stratum.

The pre-Triassic waters do not contain much alkalinity and it was difficult to accept active reduction in these waters until one could account for the carbon dioxide liberated by the reaction. For every mol of sulphate reduced two mols of carbon dioxide are formed, and one would expect a high alkalinity in the waters in which this reaction occurred. Recent work on the natural gases of this region by the author has shown that the older formations quite often yield gases containing notable quantities of carbon dioxide, and the source might well be sulphate reduction.

Oil-field Waters of Colorado

Colorado has produced only about 6 pct of the total oil in the Rocky Mountain region but with the recent development of the Weber formation in the Rangely field the state is occupying a more important place in oil production. The correlation of oil-field waters in this state is hampered by the lack of analyses, probably due to its former small oil production; most of the analyses are scattered and with the exception of two fields in the state no serious effort has been made to survey thoroughly any particular area.

The following analyses are believed representative for the strata and fields below. Only the producing fields are considered. When available, pH, depth and source of sample are given.

Hiawatha (East and West)

Oil and gas production at Hiawatha comes from three lenticular oil sands between depths of 2032 to 2512 ft in the Wasatch formation of lower Eocene age. The formation in this area is more than 5000 ft thick and contains, in addition to the three oil sands, other water-bearing lenticular sand bodies. The operators have been conscientious about testing every sand body and obtaining water samples in an effort to correlate these lenticular sands from well to well. The analyses of these waters are extremely variable. They have concentrations ranging from 1500 to 32,000 ppm total solids and a chloride content varying between 65 and 20,000 ppm. The water is saline, the salinity being caused almost entirely by chloride. The erratic nature of these waters points to the lack of continuity in the sands. Three typical analyses of Wasatch water in this field are given in Table 1; No. 1 is from the first oil-producing sand.

Table 1—*Typical Analyses of Wasatch Water, Hiawatha Field*

	No. 1	No. 2	No. 3
Na	1,751	5,873	10,594
Ca	94	30	903
Mg	40	44	409
SO_4	867	18	162
Cl	2,009	7,889	18,939
CO_3	0	146	0
HCO_3	575	2,005	115
T.S.	5,044	14,987	31,064
pH			
Source	DST	Bailer	Storage tank
Depth	2,234–2,287	3,350	2,310–2,354

Iles Dome

The principal oil production at Iles comes from the Sundance formation with a few wells producing from the Mancos shale and the basal sandstone of the Morrison formation. The zones which are capable of producing water and, therefore, enter into production problems are the water-bearing Dakota sandstone, the Morrison formation and the Sundance formation. These waters can be differentiated, one of the important correlation points being the sulphate in the Morrison water, the Dakota and Sundance waters containing only traces or none at all. The Sundance water has been sampled and analyzed more than any other water in the field; it varies, ranging from a low of about 1500 to as high as 4000 ppm total solids, the higher concentrated water being

associated with oil. A deep test in this field in 1947 obtained a sample of Weber water, its dilute nature indicating poor possibilities for production in this zone. Typical analyses of these waters are as shown in Table 2.

Moffat Dome

Production at Moffat is from the Dakota sandstone and Sundance formation and like Iles, there are three waters that enter

TABLE 2—*Typical Analyses of Waters of Iles Dome*

	Dakota	Morrison	Sundance	Weber
Na	434	1,382	1,307	741
Ca	11	0	0	0
Mg	tr	0	0	0
SO_4	tr	424	0	114
Cl	38	257	258	337
CO_3	0	121	0	210
HCO_3	1,120	2,440	3,025	815
T.S.	1,034	3,384	3,053	1 803
pH				
Source	Flow line	Stock tank	Wellhead	Swab
Depth	2,910–3,050	3,457–3,462		4,572–4,619

production problems. Only a few analyses of these waters are available to the author, thus the probable change in concentration over the structure is not known. The waters of this field bear a certain similarity to the waters of the Iles field in that the Morrison water contains sulphate and the Dakota and Sundance waters are sulphate-free. Representative analyses of these waters are given in Table 3.

TABLE 3—*Representative Analyses of Waters of Moffat Dome*

	Dakota	Morrison	Sundance
Na	447	3,570	1,074
Ca	0	76	6
Mg	0	30	0
SO_4	0	560	0
Cl	109	5,000	272
CO_3	26	0	0
HCO_3	945	535	2,400
T.S.	1,047	9,486	2,532
pH	8.2		7.3
Source	Tank	Bailer	Stock tank
Depth	3,865	4,360–4,395	4,504

Powder Wash

This is another field of Wasatch (lower Eocene) oil production with lenticular sand conditions similar to Hiawatha. Two producing zones have been logged at Powder Wash, one at 3087 to 3113 ft called the Stewart and the other at 5014 to 5023 ft called the Allen sand. Water analyses from this field bear a striking similarity to analyses from the Hiawatha field and their erratic nature indicates lenticularity and discontinuity of the sand bodies. Three typical analyses of Wasatch waters from this field are as shown in Table 4.

TABLE 4—*Typical Analyses of Wasatch Water, Powder Wash Field*

	No. 1	No. 2	No. 3
Na	1,978	6,715	10,823
Ca	26	549	660
Mg	0	51	195
SO_4	tr	181	819
Cl	2,341	11,172	17,735
CO_3	57	0	0
HCO_3	1,185	295	160
T.S.	4,984	18,813	30,311
pH			
Source	DST	DST	DST
Depth	5,035–5,075	5,273–5,283	4,191–4,209

Rangely

This is one of the early Rocky Mountain fields and oil production has come from the Mancos shale at the relatively shallow depths of 400 to 1000 ft since discovery. The development of the Weber formation of Pennsylvanian age in 1945–1946 has made this one of the outstanding oil fields in the state, if not in the Rocky Mountain area. Because of the former lack of deep drilling water analyses from this field have

TABLE 5—*Analyses of Waters of Rangely Field*

	Frontier	Dakota	Morrison	Weber
Na	5,428	873	3,069	37,725
Ca	71	8	18	3,509
Mg	38	0	tr	568
SO_4	1,339	279	984	973
Cl	6,400	800	2,092	65,000
CO_3	0	tr	0	0
HCO_3	2,100	610	3,350	565
T.S.	14,309	2,260	7,810	108,053
pH				7.35
Source	Bailer	Wellhead	Casing head	DST
Depth	3,208–3,396	3,130	3,020–3,120	6,510–6,533

been rather sketchy in the past and the few analyses available are rather tentative

in correlation. Horizons which may produce water are the Frontier, Dakota, Morrison, Shinarump and Weber; of these, the Dakota and the Weber waters have been definitely identified. The Weber water is unusual in that it is the only producing oil-field water in the Rocky Mountain region that can be called a brine, resembling in this respect Mid-Continent and California oil-field waters. Analyses of four of these waters are given in Table 5, the Frontier and Morrison waters being tentative.

Wilson Creek

This is one of the newer and more important Colorado fields with oil production from the Morrison and Sundance formations of Jurassic age. It is usual, where both the Morrison and Sundance contain oil, to find the Sundance the larger and more prolific producer; but at Wilson Creek, the Morrison exceeds the Sundance. The only waters so far encountered in production problems are those of the oil producing zones and there is such a difference in the two waters that definite correlation has never been difficult. Representative analyses of the two waters are as follows:

	Morrison	Sundance
Na	1,416	5,245
Ca	26	374
Mg	0	79
SO_4	161	1,044
Cl	1,805	8,060
CO_3	tr	0
HCO_3	525	195
T.S	3,666	14,898
pH		6.8
Source		Stock tank
Depth		6,256–6,263

General Summary

Certain generalities can be observed in Colorado waters by taking into consideration both productive and unproductive areas.

The Wasatch waters, as pointed out above, are saline despite the fluviatile origin of the beds, and hardness is present to some extent in all the waters. They are erratic in concentration, and to some extent in composition, due principally to the lenticularity of the sands.

Soft, alkaline water is the rule in the Dakota sandstone. Concentrations range from about 700 to 3000 ppm total solids with an average of less than 1500 ppm. Sulphate usually is absent, or present in small quantities only. The Dakota waters for the most part exhibit circulating ground water characteristics with little evidence of stagnancy. An interesting feature of the Dakota waters is the extraordinarily high alkalinities in a few areas; the South McCallum carbon dioxide gas field is an example. Comparable to this water is the Pictured Cliffs sandstone water of the Bondad area, which has a bicarbonate content of 9000 to 10,000 ppm.

Morrison waters, on the other hand, vary from soft, alkaline types to saline waters containing appreciable hardness. In general, they are more concentrated than Dakota waters and indicate more stagnant conditions of accumulation. They vary in concentration from about 3000 to 15,000 ppm total solids, and usually contain appreciable amounts of sulphate.

Some Sundance waters have characteristics similar to Morrison waters, and others show characteristics of Dakota waters. Sulphate has been found to be absent in most of the Sundance waters and the alkaline and lower-concentrated waters are soft. The saline waters of higher concentration contain appreciable hardness, thereby resembling Morrison waters. Despite broad, general similarities in the three waters, there are sufficient points of distinction to identify them.

Oil-field Waters of Montana

The oil-field waters of Montana were covered rather thoroughly by the author in 1942, and there have been few important additions since that time. Thus, this discussion of the waters from the more im-

portant fields of the state has been condensed from the author's previous paper.*

Border-Red Coulee Nose

The oil and gas sands in the Border-Red Coulee field are lenticular, complex sands in the lower part of the Kootenai formation. It is postulated that the oil was generated in the underlying Ellis formation and migrated to the Kootenai under the influence of Ellis water. It will be noted that the Ellis and Kootenai waters are substantially indistinguishable, which tends to confirm the above postulation; further, the Kootenai waters in this field carry hydrogen sulphide and in no other field in the state has hydrogen sulphide been found in waters of Kootenai or younger. With the exception of these two waters there are easily distinguishable differences between all waters in the field, as is shown by the typical analyses in Table 6.

TABLE 6—*Typical Analyses of Waters of Border-Red Coulee Field*

	Eagle (Virgelle)	Colorado (Blackleaf)	Kootenai (Cosmos-Vanalta)	Ellis
Na	219	6,203	1,285	1,577
Ca	93	39	90	24
Mg	69	43	52	13
SO_4	546	188	0	66
Cl	10	8,800	619	755
HCO_3	500	1,415	2,880	2,940
T.S.	1,183	15,969	3,462	3,881
pH				
Source	Bleeder	Bailer	Lead line	Bailer
Depth	85–115	1,910–2,050	2,475–2,512	2,713–2,716

Bowdoin Dome

Gas production at Bowdoin is from three sandy zones in the Colorado shale. The highest (Martin zone) was the original source of the gas but produces none now; the second (Bowdoin zone) is the important gas-producing horizon; the lower (Phillips zone) is a minor producer of gas. There are no particular water problems in the field, typical analyses of the waters so far encountered in the dome being as given in Table 7. (Definitely correlated Mississippian, Devonian and Ordovician waters from deep tests drilled in 1947 are on file but have not been released.)

TABLE 7—*Typical Analyses of Waters of Bowdoin Dome*

	Eagle (Virgelle)	Colorado shale		(Quadrant)
		(Martin)	(Bowdoin)	
Na	553	2,676	3,840	269
Ca	57	54	89	544
Mg	tr	39	54	177
SO_4	0	142	47	2,180
Cl	844	4,000	6,053	200
HCO_3	190	400	255	145
T.S.	1,547	7,108	10,208	3,441
pH				
Source	Siphon	Bailer	Bailer	Plunge inlet
Depth	690–780	285		3,175–3,180

Cat Creek Anticline

Prior to 1945 the principal oil-producing zone was the First Cat Creek sand, a 40 to 60 ft sandstone near the base of the Colorado shale. The Kootenai formation contains two sands, the Second and Third Cat Creek sands of which the Second Cat Creek produced a minor amount of oil. The Third sand yielded large quantities of water under artesian head with a few showings of oil and gas. Recently oil has been found in the Brindley sandstone of the Morrison(?) formation and the Schrock-Fifer sandstone of the Ellis formation.

All sands yield water. Even on the crests of the domes the First Cat Creek sand yields water with the oil, and there are very few wells that are entirely free of water. All the Cat Creek waters are under artesian head and the water is comparatively fresh, indicating active ground water circulation. The Brindley and Ellis waters indicate more stagnant conditions.

Typical analyses of Cat Creek waters are given in Table 8.

Cedar Creek Anticline

This, the only producing district in eastern Montana, is an asymmetric fold with local highs over 100 miles long, extending into the southwest corner of North

* See references at the end of the paper.

Dakota. Gas production is from sands of the Montana Group, the Judith River sand being the important producer and the Eagle sand a minor producer. Water is no serious problem at Cedar Creek, none of the wells producing more than a few barrels a day, and there is much less water in the southern part of the anticline than in the central and northern parts. The water is comparatively concentrated, as would be expected in a gas-producing horizon and a typical analysis of the Judith River water is as follows:

TABLE 8—*Typical Analyses of Cat Creek Field*

	Colorado, First Cat Creek	Kootenai		Morrison, Brindley	Ellis
		Second Cat Creek	Third Cat Creek		
Na	591	564	354	1,191	1,101
Ca	0	0	0	17	12
Mg	0	0	0	4	0
SO_4	0	39	289	1,309	598
Cl	400	57	35	462	827
CO_3	0	0	0	0	42
HCO_3	880	1,350	515	775	715
T.S.	1,394	1,324	930	3,364	2,932
pH					
Source	Flow tank	Lead line	Lead line		Swab
Depth	1,158–1,177	1,515–1,530	1,690–1,704		1,460–1,475

TABLE 9—*Typical Analyses of Waters of Cut Bank District*

	Montana Group		Colorado, Blackleaf	Kootenai			Madison
	Two Medicine	Virgelle		Upper Sunburst	Lower Sunburst	Cut Bank	
Na	1,073	386	5,706	4,197	3,427	2,835	1,074
Ca	52	0	126	59	68	35	0
Mg	55	0	35	tr	38	tr	0
SO_4	1,852	265	0	95	32	28	131
Cl	133	14	8,572	5,867	3,738	1,566	557
HCO_3	700	665	950	1,100	3,020	4,900	1,725
T.S.	3,509	992	14,906	10,759	8,788	6,874	2,610
pH							
Source	Bailer	Bailer	Bailer	Bailer	Bailer	Bailer	Bailer
Depth	224–280	140			2,848–2,860	3,081–3,120	3,150

Na	4,546
Ca	119
Mg	36
SO_4	0
Cl	7,176
HCO_3	260
T.S.	12,005
pH	
Source	Separator
Depth	826–880

Cut Bank District

The most prolific field in Montana from an oil production standpoint is the Cut Bank field. The principal oil-producing zone is the Cut Bank sand, the basal member of the Kootenai formation. Two other sands, the Upper and Lower Sunburst, lie above the Cut Bank sand; gas, oil and water have been encountered in these sands, but commercial production has been negligible to date. There are no serious water problems in the field; many wells drill to the Upper Sunburst sand before any water is encountered, and some do not find water until the Cut Bank sand is penetrated. In other parts of the field water may be encountered in the Montana Group sands or in the Blackleaf sandy member of the Colorado shale. Typical analyses of all these waters are shown in Table 9.

Kevin-Sunburst Dome

Oil production is principally from the reworked top of the Madison limestone in this field and gas production with a little oil is

found in the Sunburst sand of the Kootenai formation. Waters that may be encountered in drilling and production problems come from the Colorado shale, the gas-producing Sunburst sand, the Ellis formation (Ellis-Madison contact) and the Madison limestone. Even though the Colorado and Sunburst waters have a marked resemblance to each other, the various waters are rather easily identified and correlation is not difficult. Representative analyses are given in Table 10.

TABLE 10—*Typical Analyses of Waters of Kevin-Sunburst Dome*

	Colorado, Blackleaf	Kootenai, Sunburst	Ellis	Madison
Na	5,635	4,670	1,370	1,173
Ca	87	66	30	.200
Mg	115	60	62	168
SO_4	72	44	76	tr
Cl	8,476	5,980	775	1,771
HCO_3	1,120	2,550	2,610	1,515
T.S.	14,936	12,074	3,596	4,057
pH				
Source		Bailer	Bailer	Bailer
Depth		4,675	1,245	1,508–1,520

General Summary

The oil-field waters of Montana, as a whole, are more concentrated than equivalent formation water in Colorado and less concentrated than the same in Wyoming. The average concentration of the waters associated with oil is about 4000 ppm, with concentrations of 10,000 to 15,000 ppm in the gas areas. A noteworthy feature of many formation waters in this state is the excess magnesium over calcium even in waters containing less than 200 ppm total alkaline earths. This excess is particularly striking in the dolomitized Madison limestone of the Pondera field, the ratio of magnesium to calcium being from 4 to 6 (on the basis of parts per million).

Montana Group waters are dilute to moderately dilute solutions of sodium salts, the sulphate usually predominating. A rather concentrated, saline water occurs in those areas producing gas from a Montana Group sand.

Colorado waters are moderately concentrated to concentrated saline waters with sulphate either absent or present in small quantities only. The Kootenai waters often resemble Colorado waters in concentration but are usually more alkaline. Ellis waters often resemble the lower-concentrated Kootenai waters in chemical characteristics but contain appreciable quantities of hydrogen sulphide.

The Quadrant and Tensleep formations of central and southern Montana are notable water reservoirs yielding artesian flows of hot, secondary saline water. Their chemical composition is similar to, and identical with, waters from pre-Triassic formations of Wyoming.

The waters of the Madison limestone contain primary characteristics in the Sweetgrass Arch fields. Secondary alkalinity shows up in the Kevin-Sunburst and Pondera waters. In the southern part of Montana, Madison waters carry secondary salinity.

OIL-FIELD WATERS OF WYOMING

The oil-field waters of Wyoming have been surveyed and discussed rather thoroughly and a number of excellent papers have been published on the subject. There are several reasons for the large number of analyses of Wyoming waters extant as against the much smaller number from all other states in the Rocky Mountain region combined. First, and most important, the operating companies have been water-conscious and have been in the habit of taking water samples as a source of engineering and geological information. Too, the natural grouping of the oil and gas fields into basins has resulted in regional correlations that has increased the value of water analyses. Again, as the early publications on water analyses in the Rocky Mountain area dealt with specific Wyoming oil fields, it is probable that interest

was thus centered on Wyoming oil-field waters.

The main structural basins in Wyoming are the Big Horn Basin, Wind River Basin, Powder River Basin, Shirley Basin, Hanna Basin, Laramie Basin and Sweetwater Basin (Great Divide Basin). The important oil and gas producing fields are found in the Big Horn, Wind River, Powder River and Sweetwater basins.

It has been noted that waters from a particular stratum, although variable in concentration, apparently have definite chemical characteristics in a particular basin, lending themselves to probable identification in untested structures in the basin. Further, correlations throughout the state, regardless of basin, have shown broad, general characteristics useful for identification. This does not mean that the Dakota water at Lance Creek, for example, will correlate with equivalent water at Elk Basin but it does mean that a Cretaceous water in one section of the state will resemble, as regards chemical characteristics, a Cretaceous water in another section of the state. Thus, tentative correlations by age are possible wherever encountered in the state. This is particularly striking in the two great age divisions of the strata in the state pre-and post-Triassic. The rule, with some exceptions of course, is: primary characteristics in waters of post-Triassic strata and secondary characteristics in waters of pre-Triassic formations.

The following discussion of the more important fields of the state will emphasize the new information on oil-field waters obtained by deeper drilling.

Badger Basin

One of the older, deep oil-producing fields in the Rocky Mountain area is that of Badger Basin, a dome in Park County. Oil production is from sands of the Frontier formation at average depths of 8500 ft. There has been little water trouble in this field and the first samples were not obtained until 1942. Tentative correlations of the few samples obtained are as follows:

	Lance	Frontier
Na	1,789	4,432
Ca	0	62
Mg	0	0
SO_4	48	44
Cl	2,336	6,384
HCO_3	665	910
T.S.	4,500	11,369
pH		
Source	Flow tank	Gun barrel
Depth	4,303–4,313	8,791

Bailey Dome

One of the more recent oil fields in the state is Bailey dome, Carbon County, oil production being found in the Sundance formation. It is interesting to note that of the waters correlated with definite strata in the field, the Cloverly and Sundance waters are typical Cretaceous and Jurassic waters with high alkalinity; the Tensleep water is characteristic of the usual Tensleep water in the state, secondary salinity being present and alkalinity being low. Analyses of these waters are given in Table 11.

TABLE 11—*Water Analyses of Bailey Dome*

	Cloverly			
	Dakota	Lakota	Sundance	Tensleep
Na	2,700	1,437	1,332	572
Ca	0	44	20	303
Mg	0	12	tr	56
SO_4	125	119	tr	1,656
Cl	1,902	1,060	2,270	240
HCO_3	3,735	2,035	2 270	240
T.S.	6,564	3,673	3,240	2,924
pH				
Source	DST	DST	DST	Swab
Depth	4,505	4,652	5,085	6,961–7,320

Baxter Basin (North, Middle, South)

The Baxter Basin fields, Sweetwater County, are domes along the axis of the Rock Springs anticline, North Baxter being about 1200 ft lower structurally than South Baxter. These fields are important gas producers, the Dakota and Sundance formations yielding gas at North Baxter and the Frontier and Dakota formations

at Middle and South Baxter. The water analyses from the Cretaceous sands of these fields show many irregularities, probably due to the wedge nature of the sandstones, and the Sundance waters vary to some extent over the structures and particularly with depth. The Tensleep water, Table 12, is a tentative correlation only and known Tensleep analyses will have to await further testing of the sand.

TABLE 12—*Water Analyses of Baxter Basin Field*

North

	Frontier	Dakota	Sundance	Tensleep
Na	10,879	6,535	5,288	10,606
Ca	222	60	23	1,245
Mg	125	57	tr	209
SO_4	0	101	151	1,915
Cl	16,667	10,000	3,900	15,694
HCO_3	1,490	475	7,200	3,550
T.S.	28,626	16,986	12,902	31,415
pH				
Source			DST	DST
Depth	1,724	4,120–4,290	3,828–3,844	6,339

Middle

	Frontier	Dakota
Na	21,114	6,455
Ca	170	0
Mg	93	0
SO_4	37	23
Cl	30,350	5,928
HCO_3	4,750	6,900
T.S.	54,100	15,799
pH	8.1	
Source	DST	DST
Depth	2,012–2,030	2,359–2,367

South

	Frontier	Dakota	Sundance
Na	8,790	4,093	3,162
Ca	0	56	12
Mg	0	33	tr
SO_4	0	0	153
Cl	8,150	4,032	3,250
CO_3	1,047	0	64
HCO_3	7,175	4,260	2,510
T.S.	21,515	10,309	7,876
pH			
Source			Bailer
Depth	1,780–1,848		3,685

Beaver Creek

The Beaver Creek dome, Fremont County, is the south dome of the Beaver Creek anticline and produces distillate and gas from a sand in the Morrison formation. In 1946, three wells were completed in the Lakota sand for gas production. The following analyses are tentative, positive correlation being possible only with further development:

	Muddy	Lakota
Na	1,228	4,224
Ca	27	10
Mg	13	tr
SO_4	501	174
Cl	645	5,247
CO_3	96	79
HCO_3	1,465	1,830
T.S.	3,230	10,634
pH	7.75	7.95
Source		
Depth		9,108

Big Hollow

This field is a dome in the Laramie Basin, Albany County, which has produced oil from the Muddy sandstone of the Thermopolis shale at the relatively shallow depths of 900 ft. Deeper drilling encountered water in the Cloverly formation and Tensleep sandstone, the Cloverly water being dilute and the Tensleep water correlating favorably with equivalent waters throughout the state. Typical analyses are given in Table 13.

TABLE 13—*Water Analyses of Big Hollow Dome*

	Thermopolis (Muddy)	Upper Cloverly	Tensleep
Na	1,382	378	785
Ca	0	0	205
Mg	0	0	11
SO_4	15	184	1,881
Cl	1,397	171	135
CO_3	180	0	0
HCO_3	880	475	135
T.S.	3,407	967	3,083
pH			
Source	Lead line		DST
Depth	880–925	1,400–1,500	

Big Medicine Bow

Medicine Bow, now known as Big Medicine Bow, Carbon County, is an asymmetrical anticline producing oil and gas from the Sundance formation. Before the discovery of Sundance production one well flowed a small quantity of oil from the Frontier

formation. There are apparently two Sundance sandstones present in the field, the first, which some include in the Morrison formation, being about 50 ft thick and the second about 100 ft thick; a 50-ft shale and limestone unit separates them. Both sands contain oil, gas and water. Representative analyses of waters in this field are given in Table 14.

TABLE 14—*Analyses of Waters in Big Medicine Bow Field*

	First Sundance	Second Sundance	Tensleep
Na	752	664	605
Ca	0	0	475
Mg	0	0	63
SO_4	264	422	2,024
Cl	41	167	385
CO_3	59	54	0
HCO_3	1,470	825	135
T.S.	1,839	1,713	3,618
pH			
Source	Flow tank	Flow line	DST
Depth	5,538–5,596	5,606–5,698	7,003–7,037

Big Muddy

This is one of the older fields in the state and is a slightly faulted dome lying in Converse County. Oil production is from the Shannon sandstone of the Steele shale, the Wall Creek sands of the Frontier formation, and the Dakota and Lakota sands of the Cloverly formation. Serious water conditions are present in all sands and there are very few, if any, wells that produce oil free from water. Typical analyses of the various formation waters are shown in Table 15.

TABLE 15—*Water Analyses of Big Muddy Field*

	Shannon	Frontier	Lakota	Sundance
Na	4,989	2,976	1,318	1,492
Ca	77	0	0	0
Mg	49	0	0	0
SO_4	0	0	485	1,330
Cl	7,714	1,976	616	686
CO_3	0	tr	67	37
HCO_3	450	4,505	1,675	1,015
T.S.	13,050	7,167	3,310	4,044
pH				
Source	Lead line	Lead line		Sump
Depth	912–944	3,070–3,080	4,353–4,364	4,240–4,260

Big Sand Draw

A sharply folded, asymmetrical anticline in Fremont County, Big Sand Draw, was discovered in 1918. It was proved for gas production from the Frontier and Cloverly formations and was operated as a producing gas field until comparatively recently. Deeper drilling in 1942 uncovered a large reservoir of oil in the Tensleep formation and this sand is now in the process of development. There have been no water problems to date in the field, most of the samples so far obtained coming from the flanks of the structure. A typical analysis of the Frontier water is as follows:

Na	2,252
Ca	16
Mg	tr
SO_4	26
Cl	2,600
CO_3	tr
HCO_3	1,518
T.S.	5,640
pH	
Source	Bailer
Depth	3,625–3,720

Black Mountain

Black Mountain, Hot Springs County, is a long, narrow, basinward anticline with oil production from the Embar, Tensleep and Madison formations. Water problems are serious in this field. Only two wells out of eight produced oil from the Embar though all wells were located favorably on the structure; lenticular zones of variable permeability permits the interfingering of water, causing wells higher structurally to produce water while lower wells produce clean, or almost clean, oil. Dilute, artesian water is produced with the oil from the Tensleep formation. One well produces from the Madison formation and the water associated with the oil is dilute and similar to the artesian Tensleep water. Typical analyses are given in Table 16.

Byron

The Byron structure is a faulted anticline in Big Horn County, about two miles northeast of the Garland field. Gas production comes from the Frontier formation and oil

TABLE 16—*Typical Water Analyses of Black Mountain Field*

	Embar	Tensleep	Madison
Na	428	70	5
Ca	673	78	75
Mg	99	20	37
SO_4	1,935	92	15
Cl	35	12	22
CO_3	34	0	0
HCO_3	1,097	385	370
T.S.	3,743	461	336
pH			8.0
Source		Bleeder	Treater
Depth		3,176	3,965–3,973

production from the Embar and Tensleep formation; one well found some oil in the Sundance. These formations are similar to equivalent strata at Garland but lie about 2000 ft deeper at Byron. There are no water problems in the field, typical analyses of those analyzed is shown in Table 17.

TABLE 17—*Typical Water Analyses of Byron Field*

	Frontier	Embar	Tensleep
Na	1,132	3,470	51
Ca	0	374	593
Mg	0	94	154
SO_4	9	6,807	1,376
Cl	129	794	30
CO_3	145	0	0
HCO_3	2,475	815	975
T.S.	2,632	11,940	2,683
pH	8.45		6.7
Source		Lead line	
Depth	2,000	5,250–5,322	

Cole Creek

Cole Creek, Natrona and Converse counties, is a large symmetrical dome with about 500 ft of closure producing oil from the Shannon sandstone of the Steele shale. Oil saturation has been found in the Dakota and Lakota sands, of which the Lakota has become a minor producer. Water is produced with the oil from edge wells of the Shannon sand and a little water is produced by crest wells. Typical analyses of formation waters are given in Table 18.

Crooks Gap

Although tested as early as 1925, Crooks Gap, Fremont County, did not become a commercial oil field until 1945. Oil produc-

TABLE 18—*Typical Water Analyses of Cole Creek Dome*

	Lance	Shannon	Lakota
Na	345	6,729	1,695
Ca	57	63	52
Mg	28	24	tr
SO_4	493	0	863
Cl	25	9,900	1,671
HCO_3	560	1,135	685
T.S.	1,223	17,274	4,618
pH			
Source	Well head	Separator	Swab
Depth		4,645–4,679	8,002–8,027

tion is from the Cloverly formation and water analyses to date are too few to make definite correlations. However, the analysis below is believed to be Cloverly water:

Na	2,864
Ca	0
Mg	0
SO_4	106
Cl	3,619
HCO_3	1,240
T.S.	7,199
pH	
Source	
Depth	

Dallas Dome

Dallas, Fremont County, is the oldest oil field in the state, having been discovered in 1884 when oil was located at a depth of 300 ft. The field, together with Lander and Derby fields, is a local dome on the long Lander anticline and produces oil from the Embar and Tensleep formations. All wells in the field produce water estimated at about 4 bbl of water for each barrel of oil produced. The base of the Tensleep formation contains dilute water under artesian head and the similarity between this water and some of the Embar waters encountered suggests that artesian Tensleep water has entered the Embar formation. Typical analyses of these waters are as follows:

	Embar	Tensleep
Na	276	41
Ca	139	48
Mg	48	20
SO_4	648	67
Cl	55	29
HCO_3	480	220
T.S.	1,402	314
pH		
Source	Flow line	Casing head
Depth	655–698	

Derby Dome

Derby Dome, Fremont County, is on the same line of folding as Dallas but about 4½ miles southeast. Oil production is from the Embar and Tensleep formations and, like Dallas, considerable water is produced with the oil. Estimates of 4 bbl of water per barrel of oil produced have been made and it is noted that artesian water occurs in the base of the Tensleep formation. Typical water analyses are:

	Embar	Tensleep
Na	373	4
Ca	220	35
Mg	43	22
SO_4	1,178	22
Cl	12	3
HCO_3	355	195
T.S	2,001	182
pH		
Source	Casing head	Casing head
Depth	1,942–2,055	

Elk Basin

Elk Basin, Park County, is an extremely faulted basinward dome with several thousand feet of closure. Discovered in 1915, oil production was from the Frontier sands with some gas production from the Cloverly sands. The field came into prominence in late 1942 with the discovery of oil in the Tensleep sandstone and has become one of the most prolific producers of oil from the Pennsylvanian stratum in Wyoming. The analyses of Tensleep waters from this field are erratic and inconsistent, the concentration varying from a minimum of about 5000 to as high as 20,000 ppm. The average concentration of the waters associated with oil is about 10,000 ppm. Typical analyses are given in Table 19.

Frannie

The Frannie field, Park County, is an asymmetrical, elongated dome transversely cut by two faults. Oil production is from the Tensleep and Madison formations, the major production coming from the Tensleep sandstone. Typical water analyses from Frannie are shown in Table 20.

TABLE 20—*Typical Water Analyses of Frannie Field*

	Greybull	Tensleep	Madison
Na	419	206	11
Ca	tr	639	207
Mg	0	128	69
SO_4	329	2,230	483
Cl	43	28	tr
CO_3	59	0	0
HCO_3	533	255	390
T.S	1,114	3,356	951
pH			
Source			
Depth		2,650	3,169–3,343

Garland

The Garland structure, Big Horn County, is an extremely faulted basinward dome producing oil and gas from the Frontier, Tensleep and Madison formations, and gas from the Cloverly Group sandstones. It is interesting to note that the water analyses from this field are characteristic and typical of the strata from which sampled. The soft alkaline Frontier water is typical of the usual Frontier water in the state; the secondary saline Embar and Tensleep waters, with the higher concentration of the Embar and the lower chloride of the Tensleep, are

TABLE 19—*Typical Water Analyses of Elk Basin Field*

	Eagle	Frontier	Dakota	Embar	Tensleep	Madison
Na	1,303	3,867	2,940	2,126	3,940	1,652
Ca	40	24	50	570	222	383
Mg	20	tr	tr	86	55	105
SO_4	1,963	0	3,560	5,010	6,590	2,855
Cl	80	5,275	1,548	140	992	1,000
HCO_3	1,049	1,257	770	1,205	1,330	730
T.S	3,922	9,784	8,477	8,525	12,453	6,354
pH						7.35
Source		Lead line		DST	Flow line	DST
Depth	250	1,845–1,865	4,045–4,075	5,250–5,282	6,090–6,269	6,616–6,649

representative of the average all over the state. The Madison waters from Garland, though, are erratic in composition and concentration, varying from 1000 to 4000 ppm total solids. Water analyses are given in Table 21.

TABLE 21—*Water Analyses of Garland Field*

	Frontier	Embar	Tensleep	Madison
Na	4,575	1,423	232	48
Ca	0	456	549	352
Mg	0	81	143	70
SO_4	0	4,084	1,680	971
Cl	2,305	44	157	27
HCO_3	8,180	305	525	270
T.S.	10,901	6,238	3,057	1,601
pH		7.0	8.3	7.65
Source	Flow tank	DST	Lead line	DST
Depth	3,223	3,275–3,356	4,462–4,535	4,779–4,825

Gebo

Gebo dome, Hot Springs County, is one of the more recent oil fields of the state, having been discovered the latter part of 1943. Oil production is from the Embar limestone. There are at this writing insufficient water analyses to make definite correlations but tentative analyses of the Sundance and Embar waters are given below:

	Sundance	Embar
Na	903	4,261
Ca	59	357
Mg	24	80
SO_4	1,348	6,518
Cl	100	1,778
HCO_3	815	1,460
T.S.	2,835	13,712
pH		
Source	Lead line	
Depth	3,380	4,568–4,702

Grass Creek

Grass Creek, Hot Springs County, is an elongated basinward dome with oil production from the Frontier, Embar, and Tensleep formations and some gas from the Muddy and Greybull sands of the Dakota Group. The only water analyses available from this field are from the Embar and Tensleep formations, as follows:

	Embar	Tensleep
Na	1,172	556
Ca	543	386
Mg	197	155
SO_4	2,584	1,880
Cl	715	343
HCO_3	1,240	450
T.S.	5,821	3,541
pH		
Source	Flow tank	Flow tank
Depth	3,919–3,993	4,397–4,512

Hamilton Dome

This field is a highly faulted anticline in Hot Springs County producing oil from the Chugwater, Embar and Tensleep formations. Typical water analyses are given in Table 22.

TABLE 22—*Typical Analyses of Waters of Hamilton Dome*

	Chugwater	Embar	Tensleep
Na	15,349	3,913	946
Ca	696	114	444
Mg	81	156	110
SO_4	12,413	5,420	1,489
Cl	15,810	1,930	515
CO_3	0	0	0
HCO_3	285	1,310	1,035
T.S.	44,489	12,178	4,309
pH		7.9	7.3
Source		Well head	Well head
Depth	2,410–2,680		

Herrick Dome

Herrick dome, Albany County, is a 1947 discovery. Production was found in the Tensleep sandstone and the only water analyses available are from the producing formation. A typical Tensleep analysis is as follows:

Na	2,027
Ca	400
Mg	214
SO_4	5,271
Cl	410
HCO_3	270
T.S.	8,455
pH	7.85
Source	DST
Depth	3,657–3,701

Hidden Dome

The oil discovery in Hidden dome, Washakie County, was made in 1932, although gas had been produced from the field since 1917. Production was from the upper

Frontier sandstone. In 1947 oil was found in the Tensleep sandstone and the field now is in the process of development. The only water analyses from this field available to the author are from the Tensleep, tabulated below. The dilute nature of the water is due to meteoric feed where the sandstone crops out a few miles from the field:

Na	29
Ca	59
Mg	52
SO_4	8
Cl	27
HCO_3	460
T.S.	401
pH	8.4
Source	DST
Depth	

Kirby Creek

Kirby Creek, Hot Springs County, is a narrow asymmetrical anticline along the axis of the Zimmerman Butte anticline. Production was originally from the Frontier sand, there being by 1938 four small pumping wells with a total daily production of about 7 bbl of oil and 35 bbl of water. In 1944 oil production was found in the Embar formation. Pre-Triassic waters have not been definitely correlated as yet, thus the Embar and Tensleep analyses in Table 23 are tentative:

TABLE 23—*Water Analyses of Kirby Creek*

	Frontier	Embar	Tensleep
Na	477	1,437	195
Ca	0	25	41
Mg	0	tr	15
SO_4	0	2,434	388
Cl	9	75	23
CO_3	128	0	0
HCO_3	990	670	185
T.S.	1,101	4,300	753
pH			
Source	Lead line		DST
Depth	402–495	3,644–3,652	3,677–3,688

La Barge

The La Barge oil field, Lincoln and Sublette counties, is on a long, narrow, asymmetric anticline with two highs, one the La Barge field and the other the North La Barge field. Oil production is from formations of Tertiary age and La Barge was the first field in the Rocky Mountain region to produce oil commercially from the Tertiary. There are at least two, possibly three, distinct divisions of the main producing zone, all containing oil, gas and water. Typical water analyses from these fields are given in Table 24.

TABLE 24—*Typical Water Analyses of the La Barge Fields*

	La Barge		North La Barge
	Upper Sand	Lower Sand	
Na	1,245	3,458	4,504
Ca	33	0	60
Mg	20	0	17
SO_4	65	0	29
Cl	850	3,800	6,413
CO_3	0	0	120
HCO_3	1,960	2,640	905
T.S.	3,177	8,558	11,588
pH			
Source	Tubing head	Tubing head	
Depth	600+	900+	2,005–2,030

Lance Creek

The Lance Creek oil field, Niobrara County, is the state's largest oil field from standpoint of daily production, having achieved that honor in 1940. It is a broad dome with about 650 ft of closure on the elongated, asymmetrical Lance Creek anticline. The principal oil-producing zone is the Minnelusa formation with its four lenticular, intercommunicating Leo sandstone bodies. Some production comes from the Sundance formation and oil has been found in, and produced from, the Wall Creek, Newcastle and Fall River sands. The Basal Sundance water from this field shows the characteristic chloride and concentration increase up structure, the waters associated with oil averaging about 10,000 ppm total solids and 3000 ppm chloride as against 6000 and 500, respectively, for those down structure. There are no appreciable differences in chemical composition or concentration between the waters in the Leo sandstone zones of the Minnelusa formation, which indicates intercommuni-

TABLE 25—*Typical Water Analyses of Lance Creek Field*

	Fall River	Basal Sundance	Minnelusa		
			Converse	Leo	Bell
Na	834	3,445	1,669	632	765
Ca	0	192	454	307	251
Mg	0	35	53	59	60
SO_4	0	3,663	3,873	1,322	1,929
Cl	52	2,761	356	606	250
HCO_3	2,125	495	545	185	215
T.S.	1,931	10,339	6,673	3,017	3,361
pH					
Source	Flow tank	Flow tank			DST
Depth	3,405–3,433	4,295–4,345	4,530–4,568	5,512–5,542	5,482–5,517

cation of the zones. Typical water analyses from this oil field are given in Table 25.

Lander (Hudson)

The Lander anticline, Fremont County, is on the same major line of folding as that of Dallas and Derby domes. Oil production is from the Embar limestone and Tensleep sandstone, and almost all the wells produce water with the oil. Typical water analyses are:

	Embar	Tensleep
Na	117	34
Ca	109	48
Mg	28	12
SO_4	256	60
Cl	38	6
HCO_3	390	190
T.S.	740	247
pH		
Source	Lead line	
Depth	1,150	2,148

Little Buffalo Basin

This field occupies two elliptical domes with a total closure of about 1600 ft in Park County. Gas production comes from sandstones in the Frontier formation and oil production from the Embar and Tensleep formations. Typical water analyses are shown in Table 26.

TABLE 26—*Typical Water Analyses of Little Buffalo Basin*

	Frontier	Dakota	Embar	Tensleep
Na	3,062	2,174	777	710
Ca	24	40	756	373
Mg	tr	16	193	135
SO_4	58	864	2,631	1,229
Cl	3,576	2,095	270	343
HCO_3	1,977	1,270	1,525	1,545
T.S.	7,692	5,814	5,377	3,550
pH				
Source		Swab	DST	
Depth		3,020	5,068–5,078	

Lost Soldier

The Lost Soldier field, also known as Little Lost Soldier, Sweetwater County, is a highly faulted, elliptical dome en echelon with the west end of the Wertz-Mahoney-Ferris anticline. Oil production is from

TABLE 27—*Typical Water Analyses from Lost Soldier Field*

	Frontier	Muddy	Dakota	Lakota	Sundance	Tensleep
Na	5,376	3,909	1,781	2,219	1,649	1,724
Ca	36	0	0	32	15	470
Mg	tr	0	0	20	0	68
SO_4	0	0	0	265	0	1,933
Cl	5,100	3,202	1,119	1,300	996	1,954
HCO_3	5,595	4,870	2,800	3,510	2,710	530
T.S.	13,263	9,506	4,277	5,436	3,992	6,410
pH						
Source	Flow tank	Lead line	Lead line	Flow tank	Flow tank	Flow tank
Depth	225–305	1,930–1,950	1,971–1,985	2,335–2,338	2,150–2,175	5,262–6,473

the Frontier sandstones, Dakota sandstone, Lakota sandstone, Morrison formation, Sundance formation and Tensleep sandstone. Most of the wells in the post-Triassic formations produce varying amounts of water but as yet little water is produced from the Tensleep. Typical analyses are given in Table 27.

Mahoney

The Mahoney dome gas field, Carbon County, is a broad, oval anticline producing gas from the Dakota and Sundance sands and oil from the Tensleep. Water has been flooding the Dakota sand but the Sundance and Tensleep formations have not been troubled to any extent with water problems. Typical analyses of waters from this field are given in Table 28.

TABLE 28—*Typical Analyses of Water from Mahoney Field*

	Frontier	Sundance	Tensleep
Na	2,346	2,056	232
Ca	0	0	540
Mg	0	0	125
SO_4	0	76	1,835
Cl	1,467	2,392	172
CO_3	370	49	0
HCO_3	2,950	1,145	260
T.S.	5,634	5,136	3,032
pH			
Source	Casing head	Lead line	Lead line
Depth	1,985–2,025	3,195–3,390	4,293–4,505

Maverick Springs

Maverick Springs, Fremont County, is an elongated dome on the Maverick Springs anticline producing oil from the Embar and Tensleep formations. As the wells begin in either Sundance or Chugwater beds, the waters likely to be encountered are few. Typical analyses are as follows:

	Embar	Tensleep
Na	657	15
Ca	624	224
Mg	136	87
SO_4	2,599	469
Cl	284	36
HCO_3	535	457
T.S.	4,563	1,051
pH		
Source	Flow tank	
Depth	1,344–1,632	

Mule Creek (East and West)

The Mule Creek oil field, Niobrara County, is a low, symmetrical dome with about 250 ft of closure. Oil production has been from the Lakota sandstone with one well producing a minor amount of oil from the Minnelusa formation. Edge water encroachment has been gradual in the field but most wells produce some water. The West Mule Creek oil field is an elongated asymmetrical dome about 3 miles north and west of the Mule Creek field. It has a closure of about 600 ft and produces oil from the Dakota Group sands with one

TABLE 29—*Typical Water Analyses of Mule Creek Field*

	Mule Creek		West Mule Creek		
	Fall River	Lakota	Fall River	Sundance	Minnelusa
Na	304	413	338	1,397	714
Ca	0	0	0	290	536
Mg	0	0	0	110	178
SO_4	233	302	233	3,898	3,362
Cl	44	54	44	47	55
CO_3	59	37	0	0	0
HCO_3	315	545	433	110	56
T.S.	795	1,074	795	5,796	4,873
pH					
Source	Lead line	Lead line	Bailer	Casing head	Bailer
Depth	1,379–1,450	1,357–1,382	780–808	945–970	1,670

well producing a small amount from the Minnelusa formation. Typical water analyses from these two fields are shown in Table 29.

Mush Creek

Mush Creek, Weston County, is one of the newer light oil fields of the state, its major development occurring in 1947. The area is a stratigraphic play, production depending on development of the Newcastle sandstone toward the west. Pay is erratic and nonpredictable; dry holes often are drilled next to producing wells.

The pay ranges in thickness from 8 to 20 ft, 12 ft being considered an average for the area. Water analysis from this area have been confined to the producing sand. The Newcastle water varies in total solids from 12,000 to 17,000 ppm and is marked by comparatively high chloride and bicarbonate content. It is distinguished easily by these features from all other waters, surface or formation, in the area. A typical analysis follows:

Na	5,990
Ca	33
Mg	48
SO_4	21
Cl	5,350
CO_3	495
HCO_3	6,000
T.S.	14,887
pH	7.75
Source	
Depth	3,923–3,946

Oregon Basin (North and South)

The Oregon Basin oil and gas field, Park County, consists of two large adjoining domes separated by a narrow saddle. Both domes are cut by two or more lines of faulting. The south dome has a closure of about 800 ft and the north dome about 400 ft. Gas production comes from the Frontier, Cloverly and Morrison formations, and oil production from the Embar, Tensleep and Madison formations. The Frontier waters from both the north and south domes are dilute, soft and noncorrosive. The Tensleep wells produced clean

TABLE 30—*Typical Water Analyses of Oregon Basin Fields*

North

	Frontier	Dakota	Morrison	Embar	Tensleep	Madison
Na	619	1,263	467	1,911	1,453	406
Ca	43	0	0	459	174	770
Mg	tr	0	0	165	144	208
SO_4	10	26	0	3,929	3,112	1,848
Cl	130	993	430	490	500	196
CO_3	0	54	0	0	0	0
HCO_3	1,530	1,500	500	1,465	660	1,780
T.S.	1,564	3,074	1,143	7,674	5,707	4,303
pH						
Source	Lead line	Flow line	Bailer	Lead line	Dehydrator	Bailer
Depth		1,375–1,464	2,036–3,801	3,565–3,628	3,801	4,365–4,374

South

	Frontier	Chugwater	Embar	Madison	Flathead
Na	701	14,280	1,665	273	985
Ca	0	646	529	238	450
Mg	0	187	189	139	10
SO_4	0	10,472	3,669	1,093	1,337
Cl	488	15,850	769	196	1,333
HCO_3	1,015	135	1,000	420	44
T.S.	1,688	41,501	7,313	2,145	4,137
pH					
Source		Bailer	Lead line	Flow tank	Lead line
Depth		3,840	3,718–3,736	4,165–4,295	6,341–6,346

oil except on the edge of the field, thus these waters are not a problem. The Embar waters have been a problem, though, and most of the Embar wells in the field now are making some water. The average Embar water has a concentration of 7000 to 9000 ppm, but there are a number of wells in the northern area of the south dome that yield Embar water with concentrations of 12,000 to 20,000 ppm. Typical water analyses, including that of the Flathead sandstone of Middle Cambrian age, are given in Table 30.

Osage

The Osage oil field, Weston County, is a gentle westward dipping monocline on the southwest flank of the Black Hills uplift. Oil accumulation is caused by lensing of the Newcastle sandstone in structural terraces and oil production is from this sandstone and the overlying Belle Fourche shale. Stray water-bearing sands have been logged by several wells in this field. Some of these stray sands are rather persistent over an area and the analyses of these waters have proved confusing in the correlation of waters from this field. Typical water analyses are given in Table 31.

Table 31—*Typical Water Analyses of Osage Field*

	Greenhorn	Newcastle	Lakota	Minnelusa
Na	5,899	506	257	7
Ca	45	0	0	78
Mg	21	0	0	23
SO_4	64	65	355	43
Cl	8,785	340	8	5
CO_3	0	251	0	0
HCO_3	700	165	215	307
T.S.	15,158	1,243	780	307
pH				
Source	Bailer		Tap	Well head
Depth	639–649		1,727	2,528–2,592

Pilot Butte

Pilot Butte, Fremont County, is an irregular, asymmetric faulted dome originally producing oil from saturated zones of fractured sandy shale in the Steele shale. Deeper drilling yielded oil in the Tensleep formation but water accompanying the oil indicated that accumulation is small. Typical water analyses are presented in Table 32.

Poison Spider

Poison Spider, Natrona County, is a small dome with about 175 ft of closure on the Pine Mountain-Oil Mountain fold. Oil production is from a lower Sundance sandstone and considerable water is produced with the oil. Representative water analyses are given in Table 33.

Table 33—*Typical Water Analyses of Poison Spider Field*

	Dakota	Sundance	Tensleep
Na	349	780	419
Ca	6	0	290
Mg	0	0	75
SO_4	325	80	1,237
Cl	15	213	386
CO_3	72	192	0
HCO_3	360	1,208	135
T.S.	944	1,859	2,473
pH			7.5
Source	Bleeder	Lead line	Well head
Depth			2,706

Table 32—*Typical Water Analyses of Pilot Butte Field*

	Steele	Frontier	Dakota	Embar	Tensleep
Na	5,894	1,698	2,586	3,462	434
Ca	26	24	137	363	306
Mg	46	57	28	76	80
SO_4	0	0	4,214	7,437	1,414
Cl	7,154	1,395	559	525	220
HCO_3	3,640	2,472	1,110	325	310
T.S.	14,910	4,383	8,070	12,023	2,606
pH					
Source	Flow line		Tubing	Bleeder	Treater
Depth	735–769		3,779–3,791	6,024–6,289	6,204–6,349

Rock Creek

The Rock Creek oil field, also known as Rock River oil field, Carbon County, is an asymmetric anticline on the east slope of the Medicine Bow Mountain Range; the structure has about 1600 ft of closure. Oil production is from the Muddy sandstone, the Dakota and Lakota sandstones of the Cloverly Group, and the Sundance formation. In this field all Dakota Group wells are bottomed in the basal Cloverly sand and all exposed sands are protected by liners perforated opposite the sands; thus a water cannot be definitely correlated with a particular sand and these waters are called "Cloverly." Typical analyses of "Cloverly" and Sundance waters are given below:

	"Cloverly"	Sundance
Na	2,962	924
Ca	0	0
Mg	0	0
SO_4	0	297
Cl	3,240	245
CO_3	0	120
HCO_3	2,290	1,410
T.S	7,328	2,279
pH		
Source	Flow line	Flow line
Depth	3,313–3,360	

Salt Creek

The Salt Creek oil field, Natrona County, is an asymmetrical dome near the north end of the Salt Creek anticline. Closure is about 1600 ft and oil production has been obtained from the Niobrara-Carlile shale, three Wall Creek sands of the Frontier formation, the Muddy sandstones (locally called Lakota shale), the Lakota sandstone, the Morrison formation, two benches of the Sundance formation, and the Tensleep sandstone. The Salt Creek area has been thoroughly water-surveyed, every well that has made, or makes, water having been sampled, often several times. The water drive in the First Wall Creek sandstone has been mapped periodically by the use of water analyses and abandonment of wells has been expedited by use of water analysis data. Swedenborg and Ross, Herman Stabler, Claire and Coffin, and the author have published papers concerning the waters of this area, and without doubt more is known of the characteristics of the waters of this field than any other area in the Rocky Mountain region. Twelve typical water analyses from the Salt Creek field are given in Table 34.

TABLE 34—*Typical Water Analyses of Salt Creek Field*

	Shannon	Niobrara-Carlile	First Wall Creek	Second Wall Creek	Third Wall Creek	Lakota Shale
Na	407	2,893	1,582	5,456	6,506	3,232
Ca	126	tr	tr	8	0	10
Mg	301	0	0	0	0	0
SO_4	1,527	937	tr	0	60	82
Cl	26	2,667	550	5,988	8,500	3,250
CO_3	0	24	tr	tr	tr	4
HCO_3	990	1,850	3,250	4,200	2,650	2,920
T.S	2,874	7,431	3,731	13,517	16,369	8,014
pH						
Source	Bailer		Bleeder		Flow tank	
Depth			1,030–1,130		2,845–2,852	

	Dakota	Lakota	Morrison	Second Sundance	Third Sundance	Tensleep
Na	5,131	1,252	4,580	3,827	4,009	456
Ca	38	28	36	24	334	378
Mg	6	tr	24	12	59	82
SO_4	42	0	334	90	2,662	1,231
Cl	6,850	340	6,361	4,850	4,568	604
HCO_3	1,915	2,700	1,049	1,220	710	170
T.S	13,009	2,948	11,835	9,483	11,981	2,836
pH						
Source	Bailer	Bleeder		Bailer	Flow tank	Well head
Depth	2,280–2,310	2,410–2,476		2,690		3,803

Steamboat Butte

This field was discovered in 1942 and consists of an elongated dome with about 250 to 300 ft of closure lying in Fremont County. Oil production is from the Sundance and Tensleep formations. The Dakota sand has yielded some oil and the Embar limestone shows saturation in crest wells. The Frontier sandstones yield gas which is used in field operations. The Sundance water in this field shows evaporite characteristics, ranging in concentration of total solids from 20,000 to 40,000 ppm. It bears a definite resemblance to Triassic waters elsewhere in the state. Typical analyses of formation waters found at Steamboat Butte are shown in Table 35.

General Summary

The striking points about Wyoming oil-field waters is the almost clean-cut separation by age into two distinct types of water, the Triassic beds acting as the dividing line. Post-Triassic formations most often contain waters in which primary characteristics predominate; pre-Triassic formations usually contain waters in which secondary characteristics are dominant. This same division applies to the crude oils, black, high-sulphur oils in pre-Triassic beds and green, low-sulphur oils in post-Triassic beds. Recent investigations by the author into the occurrences of natural gases indicate that this same division exists for the gases, pre-Triassic beds for the most part yielding gas with a much higher content of inerts.

It is interesting to note that beds of Jurassic age in one area will yield water of primary characteristics, and in another area secondary characteristics will dominate. The type of water appears to be related to the occurrence of limestone in the Jurassic beds, a secondary water similar to post-Triassic water being produced when limestone predominates. This, of course, leads to the assumption that the characteristics of oil, water and gas depend to some extent at least upon the petrography of the rocks.

In most oil fields of the state there are sufficient differences in concentration and composition of the various formation waters to make identification relatively

TABLE 35—*Typical Water Analyses of Steamboat Butte Field*

	Frontier	Dakota	Sundance	Embar	Tensleep	Madison
Na	1,706	3,035	10,012	1,496	649	261
Ca	0	0	486	424	340	369
Mg	0	0	103	85	78	77
SO_4	98	16	10,946	3,600	1,523	966
Cl	1,800	3,518	8,316	371	244	183
CO_3	72	59	tr	tr	0	0
HCO_3	1,160	1,880	355	470	795	660
T.S.	4,246	7,553	30,038	6,207	3,225	2,181
pH	7.95					6.65
Source	DST	DST	Treater	Swab	DST	DST
Depth	3,366–3,456	4,061–4,108	5,209–5,279		7,322–7,404	7,583–7,631

Wertz

The Wertz oil field, Sweetwater County, is an elliptical dome on an anticlinal axis paralleling the Sweetwater uplift. Principal oil production is from the Tensleep sandstone, younger formations yielding gas. There are no serious water problems in this field. Representative analyses are as follows:

	Sundance	Tensleep	Amsden
Na	1,657	1,856	4,727
Ca	0	376	461
Mg	0	43	127
SO_4	0	3,050	3,728
Cl	1,078	942	4,214
CO_3	72	0	0
HCO_3	2,395	795	2,600
T.S.	3,985	6,658	14,536
pH			
Source	Lead line	DST	Lead line
Depth	4,100–4,150	6,643	6,000–6,336

easy. In some of the newer fields in which formation tests were made by drill stem these differences are not now so marked because of drilling-water contamination, but analyses after wells have been on production will eliminate this contamination.

The most difficult correlations to make are those involving Embar and Tensleep waters. Usually, but by no means always, Embar waters carry a greater proportion of sodium sulphate, a higher alkalinity, and are more concentrated. Both waters usually contain hydrogen sulphide.

Conclusions

It is evident from the generally dilute nature of the Rocky Mountain oil field waters that considerable modification and dilution of the connate waters has taken place. The characteristics of some of the waters seem to indicate little change since deposition so it must be concluded that for these waters deposition occurred in a modified sea water; some present day waters point to extensive modification since deposition, so it must be concluded that for these ground water circulation has been active and extensive.

In general, oil-field waters in this region have been influenced by the petrography of the rocks in which they occur. Calcium and magnesium are absent or present only in small amounts in those sandstones in which limy breaks are at a minimum, but secondary characteristics are prominent in limestone and limy formations.

Hydrogen sulphide usually is present in waters of pre-Triassic formations, and, where present in waters of Jurrasic or Lower Cretaceous age, it is noticeable that limestone or sulphate-bearing waters also are present. This lends credence to the belief that hydrogen sulphide is a product of bacterial action in which sulphate, either in the water or in the rock, plays a leading role.

There appears to be no relationship between presence or absence of commercial oil and character of water in a structure. Commercial oil and gas fields in this region yield, associated with hydrocarbons, saline and alkaline, dilute and concentrated and fresh and stagnant waters such that no particular criteria can be found to distinguish between productive and nonproductive structures.

The value of water analyses as a means of identification of intrusive water in a well bore has been proven by field application of the data obtained in the laboratory.

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DISCUSSION

T. C. Hiestand*—The author touches on controversial matter in stating premises upon which correlation of water analyses is based. Geochemically, however, it appears to be definite that characteristics of the producing water do serve the purpose of correlating the analyses with respective reservoir zones, and that is the important point in engineering. Geologically it appears that water pressure in each reservoir zone is commonly hydrostatically adjusted to present depth, also that oil and gas accumulation is adjusted to present structural conditions with minor exceptions. In other words equilibrium exists in the fields, a majority of which are situated at the flanks of Rocky Mountain ranges. Under equilibrium it appears that any hydraulic action between entry points at exposures adjacent to mountain uplifts and discharge points at river levels maintains volumetric equalization. Geochemically, analyses reflect the cumulative complications which have occurred subsequent to deposition of reservoir formations as unconsolidated sediments, down to burial in geological basins, then recurrent uplift, folding, and erosion during mountain building. Hence, the explanations of variations in concentrations of waters are controversial.

With the advent of electrical logging in recent years, the necessity for detailed analyses of reservoir waters in oil and gas fields has arisen to establish a basis for mathematical or quantitative interpretation of the three curves: the self potential in millivolts, the normal and the lateral resistivity in ohms per cubic meter. It is not the intent to try to present a technique in these comments but rather to call attention to the important factor of water analysis in the interpretation of electric logs.

Progress investigations in these fields indicate that reservoir formations commonly have low permeability ranges, that the water concentrations are usually less than 12,000 ppm, and that the subsurface API gravities of the crudes are seldom in excess of 40°. It is commonly found that the closed structural uplifts on which fields are developed contain wells which produce only water one-third of the vertical height up from the lowest closing contour, towards the structural apex. Above this contour apparently oil-water intermix zones occur, the penetrated distances of which range from the order of 10 to 50 ft, or possibly greater. In this zone the ratio of producible water in wells diminishes gradually up dip. Above this zone the producible oil is commonly water free. In order to establish factors which affect maximum efficient rates of daily production of oil and water, respectively, for each well in fields, I believe it is economically important (1) to obtain water analyses, (2) to make mathematical or quantitative interpretations of the electric logs of the reservoir formations, and (3) to check these results against the core analyses of the reservoir formations.

Therefore, I believe, the author has contributed valuable background data for the use of the reservoir engineer as well as the development geologist working in this region.

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Volumetric and Viscosity Studies of Oil and Gas from a San Joaquin Valley Field

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Abstract

The volumetric behavior of five mixtures of black oil and natural gas and of two mixtures of condensate and natural gas from a field in the San Joaquin Valley was experimentally established. This work was carried out at 100°, 190° and 250°F in the pressure interval between 400 and 5000 psi. The viscosity of the liquid phase of four mixtures of black oil and natural gas was experimentally measured in the above-indicated temperature and pressure intervals. The effect of methane upon the precipitation of bitumen from the black oil was studied at 230°F.

Introduction

The solution of a number of the economical and technological problems which arise in connection with petroleum production is dependent upon the availability of the necessary quantitative information covering the materials involved. This requires data concerning physical properties of naturally occurring hydrocarbon mixtures at the pressures and temperatures characteristic of underground petroleum reservoirs. The experimental determination of the desired data for each situation encountered is relatively time-consuming. However, it is considered to yield results sufficiently more reliable than those obtained from correlations to justify the effort. For these reasons there was undertaken a laboratory investigation of the viscosity of the liquid phase and the volumetric and phase behavior of mixtures of oil and gas samples obtained from wells in a field located in the San Joaquin Valley.

Terminology

The nomenclature of petroleum engineering is not at present entirely standardized. Many commonly used technical terms are not everywhere given the same meanings. For the purposes of this paper the following definitions will be adopted:

Black oil refers to the dark-colored, hydrocarbon liquid obtained when the producing horizon of the well lies partly in the condensed hydrocarbon phase of the reservoir. Condensate is the term applied to the relatively volatile, pale yellow or amber-colored hydrocarbon liquid that is often obtained from the surface separator system when the producing horizon of the well lies in the gas cap of the reservoir. The gas obtained from the surface separator system is called natural gas regardless of whether the well is producing black oil or condensate.

As might be expected from the multicomponent character of naturally occurring hydrocarbon materials, the compositions of black oil, condensate and natural gas are subject to considerable variation depending upon the temperatures and pressures prevailing in the surface separator system as well as upon the overall composition of the material produced from the reservoir. In order to obtain samples capable of reproducing the total hydrocarbon material produced by the well, all oil and gas mixtures used in this investigation were com-

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posed of samples obtained from primary surface separators.

The hydrocarbon liquid and gas phases withdrawn from the primary surface separator are called trap liquid and trap gas, respectively. These materials were combined in various proportions to produce the hydrocarbon mixtures studied in the experiment.

measured at 60°F and 14.73 psi.* Similarly, the liquid formation volume is the ratio of the volume occupied by the liquid phase of a heterogeneous mixture at the temperature and pressure in question to the corresponding volume of tank oil associated with that mixture. The volume of tank oil is again measured at 60°F and 14.73 psi.

The gas-oil ratio is used as an index of

TABLE 1—*Composition of Samples Used in Volumetric and Viscosity Studies*

Component	Trap Gas		Trap Liquid		Tank Oil[a]	
	Mol Fraction	Weight Fraction	Mol Fraction	Weight Fraction	Mol Fraction	Weight Fraction
Methane	0.8360	0.6574	0.0923	0.0091		
Ethane	0.0712	0.1049	0.0400	0.0074	0.0048	0.0007
Propane	0.0566	0.1223	0.0797	0.0216	0.0393	0.0087
Isobutane	0.0056	0.0160	0.0230	0.0082	0.0145	0.0042
n-Butane	0.0158	0.0450	0.0723	0.0257	0.0655	0.0192
Isopentane	0.0032	0.0113	0.0294	0.0130	0.0287	0.0104
n-Pentane	0.0033	0.0117	0.0311	0.0138	0.0395	0.0143
Hexanes	0.0021	0.0089	0.0656	0.0346	0.0864	0.0375
Heptanes and heavier	0.0033[b]	0.0162[c]	0.5666[d]	0.8666[e]	0.7213[d]	0.9050[e]
Carbon dioxide	0.0029	0.0063				
Average molecular weight	20.40		163.1		198.8	
Gas-oil ratio	Infinity		153		0	

[a] Gravity, 34.6° API at 60°F and atmospheric pressure.
[b] Estimated average molecular weight, 100.
[c] Estimated gravity, 74° API at 60°F and atmospheric pressure.
[d] Average molecular weight indicated by freezing point lowering of benzene extrapolated to infinite dilution of solute, 249.4.
[e] Gravity, 29.7° API at 60°F and atmospheric pressure.

The volumetric data from these studies are reported in terms of specific volumes and liquid volumes. The specific volume represents the volume per unit weight of mixture while the liquid volume at a given state expresses the volume of the liquid phase per unit weight of the mixture. The liquid volume is equal to the specific volume of the system at the bubble-point state.

The volumetric properties of the hydrocarbon phases in the reservoir are customarily expressed in terms of the corresponding volume of crude liquid hydrocarbon produced; this will be called tank oil. The formation volume represents the volume occupied by the mixture at the pressure and temperature in question per unit volume of tank oil associated with that mixture. The volume of the tank oil is

the composition of the hydrocarbon material under consideration. This ratio expresses the number of cubic feet of natural gas obtained from all stages of the surface separator system per barrel of tank oil. The volumes of both the gas and the oil are measured at 60°F and 14.73 psi.

In computing the gas-oil ratio of trap-gas and trap-liquid mixture studied in the laboratory, the mixture is conceptually separated into liquid and gas constituents corresponding to the composition of the tank oil and natural gas produced at the well from which the trap samples were obtained. The volume ratios of these constituents are then calculated to establish the corresponding gas-oil ratios. The details

* All pressures reported are expressed in pounds per square inch absolute.

of this procedure have been described elsewhere.[1]

Field Samples

Samples of trap gas, trap liquid and tank oil were obtained from a producing well and forwarded to the laboratory in appropriate steel containers. Low-temperature fractional distillation analyses of these samples are given in Table 1. Additional analytical information concerning the character of the heptanes-and-less-volatile portion of the trap liquid are recorded in Table 2. The compositions of the five experimentally studied mixtures of trap liquid and trap gas are reported in Table 3. This information was obtained in accordance with procedures that already have been described.[1]

Table 2—*Properties of Heptanes-and-heavier Portion of Trap-liquid Sample Used in Volumetric and Viscosity Studies*

Mol fraction of trap-liquid sample, 0.5666
Weight fraction of trap-liquid sample, 0.8666
Gravity at 60°F, atmospheric pressure, 29.7° API
Kinematic viscosity in centistokes:
at 77°F, 12.00
at 100°F, 8.58
Viscosity-gravity factor, 0.851
Average molecular weight, 249.4[a]

Cut Volume, Per Cent	Fractionation Analysis						
	Average Boiling Point, Deg F	Gravity Deg API at 60°F	Kinematic Viscosity, Centistokes			Viscosity Gravity Factor	Weight Fraction[b]
			77°F	100°F	210°F		
10	225	58.4	0.940	0.650		0.787	0.07364
10	275	52.3	0.870	0.780		0.807	0.07608
10	354	44.6	1.270	1.110		0.825	0.07941
10	498	38.3	2.250	1.877		0.844	0.08234
60		19.6		195.7	12.65	0.879	0.55513

[a] Determined from freezing point lowering of benzene extrapolated to infinite dilution of the solute.
[b] Based upon entire trap-liquid sample.

Procedures

The equipment used in the volumetric study of hydrocarbon systems has been described.[2,3] The mixtures were prepared by displacing samples of trap liquid and trap gas from weighed containers into a stainless steel equilibrium chamber. The effective volume of the equilibrium chamber was varied by the introduction and withdrawal of mercury. An electric contact point detected the mercury-hydrocarbon interface and permitted the total volume occupied by the hydrocarbon phases to be measured with an uncertainty of approximately 0.2 pct.

Pressures were measured by means of a piston-cylinder balance[3] which had been calibrated against the vapor pressure of pure carbon dioxide at the ice-point in accordance with the procedure described by Bridgeman.[4] The pressure balance was sufficiently sensitive to detect pressure changes of 0.1 psi. The uncertainty in the pressure measurements was less than 0.2 pct.

The equilibrium cell was immersed in a rapidly circulating oil bath whose temperature was measured and automatically controlled by means of platinum resistance thermometers. The thermometer used for the temperature measurement was calibrated by comparison with a similar in-

[1] References are at the end of the paper.

strument whose characteristics had been established by the National Bureau of Standards. It is believed that the temperature of the samples when under investigation was known with an uncertainty of not greater than 0.1°F.

pressures up to 5000 psi. Fig 1 shows a typical example of the experimental results. The points represent experimentally observed equilibrium states of the system. The agreement of observations at a given state approached at a constant temperature

TABLE 3—*Compositions of Mixtures Used in Volumetric Studies*

Component	0.02066		0.05082		0.07539		0.10311		0.29778	
	Mol Fraction	Weight Fraction	Mol Fraction	Weight Fraction	Mol Fraction	Weight Fraction	Mol Fraction	Weight Fraction	Mol Fraction	Weight Fraction
Methane	0.1996	0.0225	0.3151	0.0420	0.3858	0.0580	0.4485	0.0759	0.6665	0.2022
Ethane	0.0445	0.0094	0.0494	0.0124	0.0523	0.0148	0.0549	0.0175	0.0641	0.0364
Propane	0.0764	0.0237	0.0728	0.0267	0.0706	0.0292	0.0686	0.0320	0.0619	0.0516
Isobutane	0.0205	0.0084	0.0178	0.0086	0.0161	0.0088	0.0147	0.0090	0.0096	0.0105
n-Butane	0.0641	0.0261	0.0554	0.0267	0.0500	0.0272	0.0452	0.0277	0.0287	0.0314
Isopentane	0.0256	0.0130	0.0215	0.0129	0.0191	0.0129	0.0169	0.0128	0.0092	0.0125
n-Pentane	0.0271	0.0138	0.0228	0.0137	0.0201	0.0136	0.0178	0.0136	0.0096	0.0132
Hexanes	0.0564	0.0341	0.0466	0.0333	0.0405	0.0327	0.0352	0.0320	0.0166	0.0269
Heptanes and heavier	0.4854	0.8489	0.3977	0.8234	0.3444	0.8023	0.2968	0.7789	0.1316	0.6134
Carbon dioxide	0.0004	0.0001	0.0009	0.0003	0.0011	0.0005	0.0014	0.0006	0.0022	0.0019
Average molecular weight	142.5		120.3		106.8		94.7		52.9	
Gas-oil ratio	274		460		620		811		2580	

VOLUMETRIC MEASUREMENTS

The volumetric behavior of the mixtures was determined at 100°, 190° and 250°F, for

TABLE 4—*Volumetric Properties of the Trap Liquid*

Pressure, Psia	100°F		190°F		250°F	
	Specific Volume, Cu Ft per Lb	Formation Volume	Specific Volume, Cu Ft per Lb	Formation Volume	Specific Volume, Cu Ft per Lb	Formation Volume
	(300)[a]		(414)		(503)	
B.P.	0.02009	1.110	0.02126	1.175	0.02196	1.213
400	0.02007	1.109				
600	0.02004	1.107	0.02122	1.172	0.02193	1.212
800	0.02001	1.106	0.02117	1.170	0.02186	1.208
1,000	0.01998	1.104	0.02112	1.167	0.02180	1.204
1,250	0.01994	1.102	0.02107	1.164	0.02173	1.201
1,500	0.01990	1.099	0.02101	1.161	0.02165	1.196
1,750	0.01987	1.098	0.02096	1.158	0.02158	1.192
2,000	0.01983	1.096	0.02091	1.155	0.02151	1.188
2,250	0.01979	1.093	0.02086	1.153	0.02144	1.185
2,500	0.01976	1.092	0.02081	1.150	0.02138	1.181
3,000	0.01969	1.088	0.02071	1.144	0.02126	1.175
3,500	0.01962	1.084	0.02062	1.139	0.02114	1.168
4,000	0.01956	1.081	0.02054	1.135	0.02104	1.162
4,500	0.01949	1.077	0.02046	1.130	0.02094	1.157
5,000	0.01943	1.074	0.02038	1.126	0.02085	1.152

[a] Figures in parentheses represent bubble-point pressures (B.P.) expressed in pounds per square inch absolute.

at either a higher or a lower pressure indicated a satisfactory attainment of equilibrium.

The experimental data for the five mixtures indicated were smoothed and interpolated graphically to even values of the pressure by methods which did not introduce an additional uncertainty of more than 0.1 pct. The results obtained from measurements on the trap liquid are given in Table 4, and those from the study of five mixtures of trap gas and liquid are recorded in Table 5. The bubble-point states were determined graphically from discontinuities in the first derivative of the isothermal specific volume-pressure relation. The discontinuities in the slopes of the pressure-volume isotherms of the mixture with a gas-oil ratio of 2480 cu ft per barrel were so slight as to be unobservable. Hence, no bubble-point data were obtained for this mixture. The influence of pressure and temperature upon the gas-oil ratio and formation volume of the bubble-point liquid is shown in Fig 2 and 3.

Viscosity Measurements

Apparatus for the measurement of viscosity by the determination of the velocity of a ball rolling within a closely fitting cylindrical tube filled with the fluid in question has been described.[5] The viscometer used in the present study differed slightly from that utilized earlier.[6] A three-stage centrifugal pump in a pressure vessel served to circulate the fluid with sufficient velocity to ensure the rapid attainment of equilibrium between phases. The system included an equilibrium cell whose effective volume was varied by the introduction or withdrawal of mercury, thus permitting the pressure within the viscometer to be controlled. The pressure and temperature were measured in the same manner as was employed for the volumetric studies. The viscometer was calibrated by measuring the roll time at atmospheric pressure and at a known temperature for a series of organic liquids including n-pentane, carbon tetrachloride, kerosene, and a water white oil. The viscosities of these calibrating fluids were measured at atmospheric pressure by means of an Ostwald pipette which had been calibrated with water.

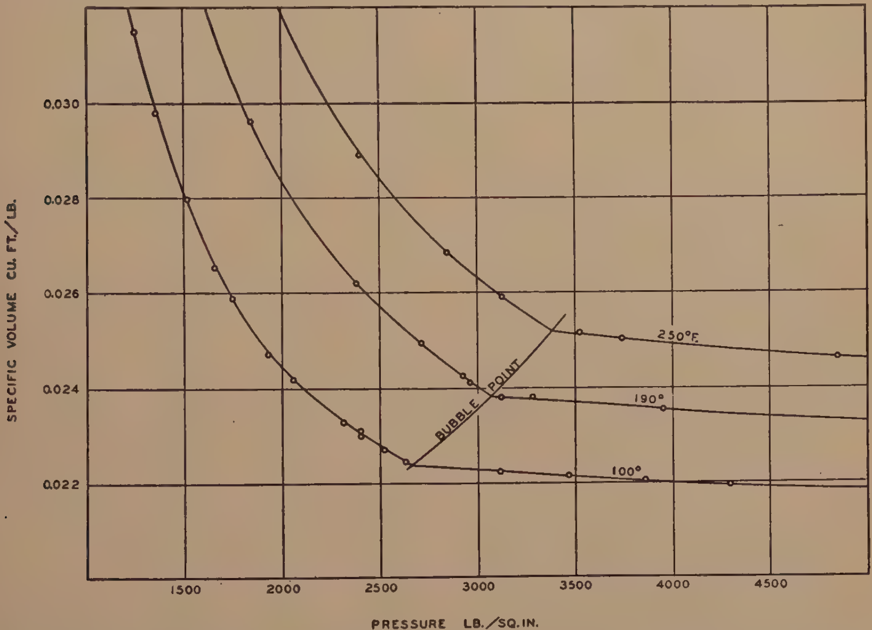

Fig 1—Specific volume for mixture with gas-oil ratio of 811 cubic feet per barrel.

An electric chronograph recorded the time required for the ball to traverse the distance between fixed electrical contacts in the roll tube. At any given state, several successive traverses of the ball yielded time intervals agreeing with each other within 0.1 pct. The experimental data at 100°F for a mixture having a gas-oil ratio of 1146 cu ft per barrel are shown in Fig 4. It is of interest to note that the discontinuity in the slope of the viscosity-pressure isotherm is more distinct than the corresponding discontinuity in the isothermal specific volume-pressure relation. In the present case the measurement of the viscosity of the liquid phase as a function of pressure provides a more sensitive means of detecting the bubble-point state than does the measurement of the total volume of the system.

The compositions of the four mixtures

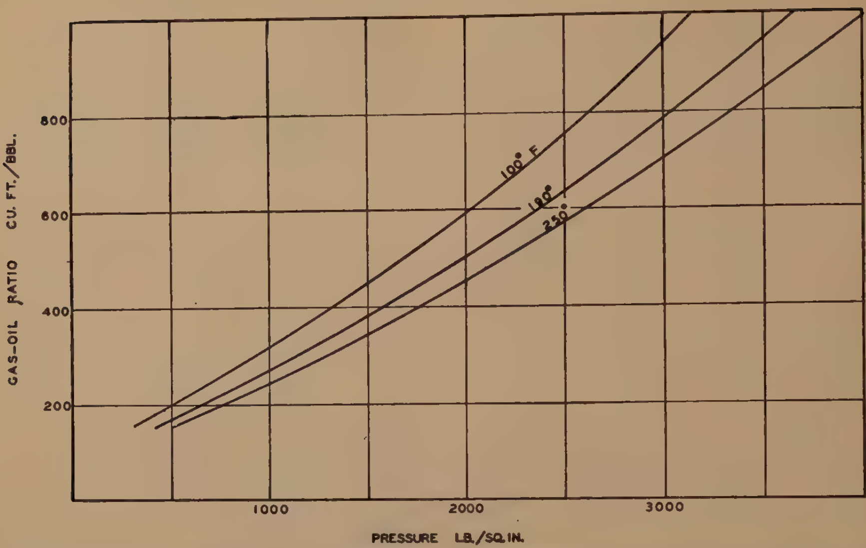

FIG 2—INFLUENCE OF PRESSURE AND TEMPERATURE UPON GAS-OIL RATIO OF BUBBLE-POINT LIQUID

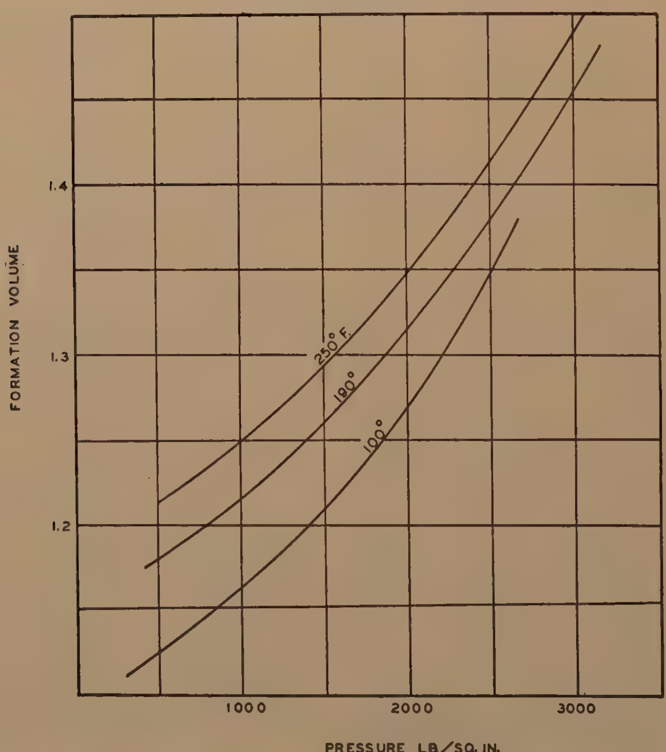

FIG 3—EFFECT OF PRESSURE AND TEMPERATURE UPON FORMATION VOLUME OF BUBBLE-POINT LIQUID.

whose viscosities were experimentally studied are recorded in Table 6 and the experimental results graphically interpolated to even values of the pressure are given in Table 7. A graphic correlation of the viscosity of the bubble-point liquid as a function of the pressure for several temperatures is shown in Fig 5.

TABLE 5—*Volumetric Properties of the Experimentally Studied Mixtures*

Pressure, Psia	100°F Specific Volume, Cu Ft per Lb	100°F Formation Volume	190°F Specific Volume, Cu Ft per Lb	190°F Formation Volume	250°F Specific Volume, Cu Ft per Lb	250°F Formation Volume
Weight fraction trap gas, 0.02066; Gas-oil ratio, 274 cu ft per bbl						
	(817)[a]		(1,020)		(1,170)	
B.P.	0.02036	1.149	0.02157	1.217	0.02239	1.263
1,000	0.02031	1.146				
1,250	0.02026	1.143	0.02151	1.214	0.02236	1.261
1,500	0.02021	1.140	0.02144	1.210	0.02228	1.257
1,750	0.02016	1.137	0.02138	1.206	0.02220	1.252
2,000	0.02011	1.135	0.02132	1.203	0.02212	1.248
2,250	0.02006	1.132	0.02125	1.199	0.02205	1.244
2,500	0.02002	1.129	0.02119	1.195	0.02298	1.240
3,000	0.01994	1.125	0.02108	1.189	0.02184	1.232
3,500	0.01986	1.120	0.02097	1.183	0.02171	1.225
4,000	0.01978	1.116	0.02087	1.177	0.02160	1.219
4,500	0.01971	1.112	0.02078	1.172	0.02148	1.212
5,000	0.01963	1.107	0.02070	1.168	0.02137	1.206
Weight fraction trap gas, 0.05082; Gas-oil ratio, 460 cu ft per bbl						
	(1,540)		(1,830)		(2,020)	
B.P.	0.02085	1.214	0.02226	1.296	0.02321	1.351
1,750	0.02080	1.211				
2,000	0.02075	1.208	0.02220	1.292		
2,250	0.02070	1.205	0.02213	1.288	0.02314	1.347
2,500	0.02065	1.202	0.02206	1.284	0.02305	1.342
3,000	0.02056	1.197	0.02191	1.275	0.02288	1.332
3,500	0.02047	1.192	0.02178	1.268	0.02272	1.323
4,000	0.02039	1.187	0.02166	1.261	0.02257	1.314
4,500	0.02030	1.182	0.02154	1.254	0.02242	1.305
5,000	0.02022	1.177	0.02143	1.247	0.02228	1.297
Weight fraction trap gas, 0.07539; Gas-oil ratio, 620 cu ft per bbl						
	(2,085)		(2,439)		(2,670)	
B.P.	0.02145	1.282	0.02296	1.372	0.02408	1.439
600	0.04823	2.882	0.05850	3.496		
800	0.03565	2.130	0.04565	2.728	0.05146	3.075
1,000	0.03039	1.816	0.03833	2.290	0.04362	2.607
1,250	0.02679	1.601	0.03243	1.938	0.03694	2.207
1,500	0.02429	1.451	0.02902	1.734	0.03258	1.947
1,750	0.02267	1.355	0.02669	1.595	0.02963	1.771
2,000	0.02170	1.297	0.02505	1.497	0.02743	1.639
2,250	0.02141	1.279	0.02382	1.423	0.02581	1.542
2,500	0.02135	1.276	0.02294	1.371	0.02464	1.472
3,000	0.02123	1.269	0.02278	1.361	0.02394	1.431
3,500	0.02112	1.262	0.02263	1.352	0.02374	1.419
4,000	0.02101	1.255	0.02248	1.343	0.02356	1.408
4,500	0.02091	1.249	0.02234	1.335	0.02338	1.397
5,000	0.02082	1.244	0.02220	1.327	0.02321	1.387

TABLE 5—(*Continued*)

Pressure, Psia	100°F Specific Volume, Cu Ft per Lb	100°F Formation Volume	190°F Specific Volume, Cu Ft per Lb	190°F Formation Volume	250°F Specific Volume, Cu Ft per Lb	250°F Formation Volume
Weight fraction trap gas, 0.10311; Gas-oil ratio, 811 cu ft per bbl						
	(2,656)		(3,067)		(3,384)	
B.P.	0.02238	1.379	0.02382	1.467	0.02519	1.552
600	0.05734	3.532	0.07224	4.450		
800	0.04408	2.715	0.05437	3.349	0.06262	3.858
1,000	0.03661	2.255	0.04521	2.785	0.05130	3.160
1,250	0.03134	1.931	0.03799	2.340	0.04352	2.681
1,500	0.02806	1.729	0.03339	2.057	0.03827	2.358
1,750	0.02590	1.596	0.03040	1.873	0.03449	2.125
2,000	0.02446	1.507	0.02831	1.744	0.03175	1.956
2,250	0.02347	1.446	0.02683	1.653	0.02976	1.833
2,500	0.02275	1.401	0.02569	1.583	0.02834	1.756
3,000	0.02228	1.373	0.02401	1.479	0.02631	1.621
3,500	0.02214	1.364	0.02366	1.458	0.02514	1.549
4,000	0.02200	1.355	0.02347	1.446	0.02493	1.536
4,500	0.02187	1.347	0.02330	1.435	0.02473	1.523
5,000	0.02174	1.339	0.02313	1.425	0.02455	1.512
Weight fraction trap gas, 0.29778; Gas-oil ratio, 2,480 cu ft per bbl						
1,250	0.06215	4.890				
1,500	0.05400	4.249	0.06915	5.441		
1,750	0.04682	3.684	0.06004	4.724	0.06854	5.393
2,000	0.04163	3.275	0.05342	4.203	0.06070	4.776
2,250	0.03805	2.994	0.04851	3.817	0.05490	4.320
2,500	0.03552	2.795	0.04465	3.513	0.05051	3.974
3,000	0.03206	2.522	0.03938	3.098	0.04421	3.478
3,500	0.03010	2.368	0.03598	2.831	0.04000	3.147
4,000	0.02897	2.279	0.03377	2.657	0.03719	2.926
4,500	0.02821	2.220	0.03223	2.536	0.03515	2.766
5,000	0.02760	2.172	0.03012	2.370	0.03360	2.644

[a] Figures in parentheses represent bubble-point pressures expressed in pounds per square inch absolute.

From the data presented in Fig 2, 3 and 5, the tabular information in Table 8 was obtained. The gas-oil ratio, formation volume, and viscosity of bubble-point liquid at the temperatures employed in this investigation are recorded in Table 8 at a number of systematically chosen pressures.

In the course of investigating the volumetric and viscous characteristics of mixtures of the gas and black oil, some trouble was encountered with the precipitation of a plastic or solid phase. The precipitation of the plastic phase was particularly noticeable in the case of the mixtures with the highest gas-oil ratios. The precipitate, which is judged to be of an asphaltic nature, tended to coat the interior parts of the

equilibrium equipment and impaired the accuracy of the results obtained from the measurement of viscosity. For this reason, it is believed that the viscosities herein reported may be in error by as much as 4 pct in the mixtures with the high gas-oil ratios. Uncertainties of not more than 2.0 pct in the viscosity of the liquid phase of the mixtures are involved at the lower gas-oil ratios.

Bitumen Studies

As has been indicated, small quantities of a solid or plastic phase were precipitated from the hydrocarbon mixtures at the higher pressures and gas-oil ratios. A limited study of the separation of bitumen at 230°F from methane-oil mixtures of varying compositions has been made.

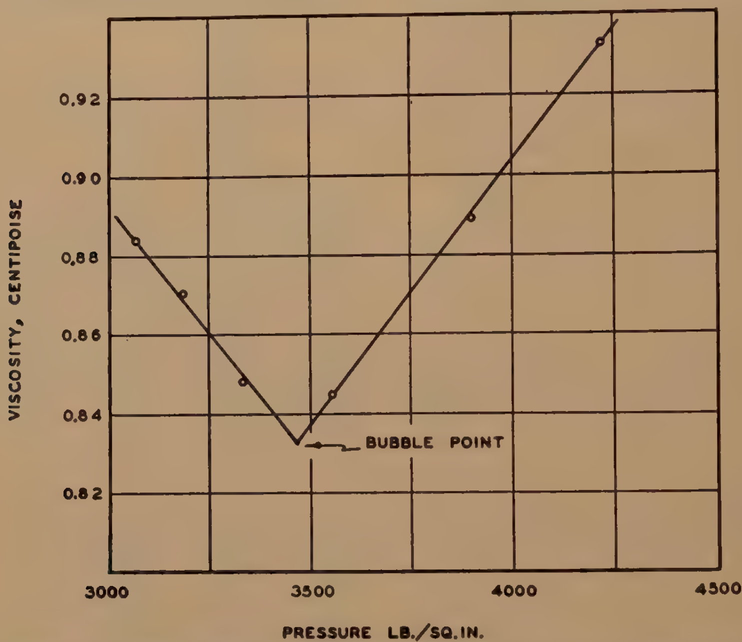

Fig 4—Viscosity of liquid phase for mixture with gas-oil ratio of 1146 cubic feet per barrel.

Table 6—*Composition of the Mixtures Used in the Viscosity Studies*

Weight Fraction Trap Gas	0.0012		0.0050		0.0670		0.1478	
Component	Mol Fraction	Weight Fraction	Mol Fraction	Weight Fraction	Mol Fraction	Weight Fraction	Mol Fraction	Weight Fraction
Methane	0.0995	0.0099	0.1212	0.0123	0.3635	0.0525	0.5243	0.1049
Ethane	0.0404	0.0075	0.0413	0.0079	0.0514	0.0139	0.0582	0.0218
Propane	0.0796	0.0217	0.0790	0.0221	0.0714	0.0284	0.0663	0.0365
Isobutane	0.0228	0.0082	0.0223	0.0082	0.0167	0.0087	0.0129	0.0094
n-Butane	0.0715	0.0257	0.0699	0.0258	0.0516	0.0270	0.0394	0.0286
Isopentane	0.0291	0.0130	0.0284	0.0130	0.0198	0.0129	0.0142	0.0127
n-Pentane	0.0309	0.0138	0.0301	0.0138	0.0210	0.0137	0.0150	0.0135
Hexanes	0.0649	0.0346	0.0630	0.0345	0.0424	0.0329	0.0287	0.0308
Heptanes and heavier	0.5613	0.8656	0.5447	0.8623	0.3611	0.8096	0.2393	0.7409
Carbon dioxide			0.0001		0.0011	0.0004	0.0017	0.0009
Average molecular weight	161.7		157.5		111.0		80.18	
Gas-oil ratio	160		182		564		1,146	

TABLE 7—*Viscosity of Liquid Phase for Experimentally Studied Mixtures*

Weight fraction trap gas, 0.0012
Gas-oil ratio, 160 cu ft per bbl

Pressure, Psia	100°F Viscosity, Centipoise	190°F Viscosity, Centipoise	250°F Viscosity, Centipoise
	(330)[a]	(460)	(550)
B.P.	4.04	1.42	0.93
200	4.40		
400	4.08		
600	4.18	1.45	0.93
800	4.29	1.50	0.96
1,000	4.39	1.54	0.99
1,250	4.51	1.61	1.02
1,500	4.65	1.67	1.06
1,750	4.79	1.74	1.10
2,000	4.93	1.81	1.14

Weight fraction trap gas, 0.0050
Gas-oil ratio, 182 cu ft per bbl

Pressure, Psia	100°F Viscosity, Centipoise	190°F Viscosity, Centipoise	250°F Viscosity, Centipoise
	(430)	(580)	(684)
B.P.	3.70	1.32	0.86
200	4.30		
400	3.76		
600	3.77	1.32	
800	3.85	1.36	0.88
1,000	3.94	1.41	0.91
1,250	4.06	1.47	0.94
1,500	4.18	1.53	0.97
1,750	4.30	1.59	1.01
2,000	4.43	1.65	1.05

Weight fraction trap gas, 0.0670
Gas-oil ratio, 564 cu ft per bbl

Pressure, Psia	100°F Viscosity, Centipoise	190°F Viscosity, Centipoise	250°F Viscosity, Centipoise
	(1,895)	(2,235)	(2,450)
B.P.	1.60	0.70	0.48
1,500	1.78		
1,750	1.66		
2,000	1.62		
2,250	1.69	0.71	
2,500	1.76	0.73	0.48
3,000	1.91	0.79	0.52
3,500	2.06	0.86	0.56
4,000	2.22	0.92	0.61
4,500	2.40	0.99	0.66
5,000	2.60	1.07	0.71

Weight fraction trap gas, 0.1478
Gas-oil ratio, 1,146 cu ft per bbl

Pressure, Psia	100°F Viscosity, Centipoise	190°F Viscosity, Centipoise	250°F Viscosity, Centipoise
	(3,470)	(4,060)	(4,500)
B.P.	0.83	0.42	0.286
3,000	0.89		
3,250	0.86		
3,500	0.84		
4,000	0.90		
4,500	0.97	0.45	0.286
5,000	1.05	0.48	0.310

[a] Figures in parentheses represent bubble-point pressures expressed in pounds per square inch absolute.

Materials

Analyses by low-temperature distillation of the samples of trap gas, trap liquid and tank oil are given in Table 9. Additional information concerning the heptanes-and-heavier portion of the trap-liquid sample is recorded in Table 10. These samples differed somewhat from the corresponding materials employed in the volumetric and viscosity studies. For that reason the information concerning the composition of the samples employed in the bitumen studies has been presented in the foregoing tables.

Experimental Procedure and Results

The asphaltic constituent of a crude oil consists of a complex mixture of substances of high molecular weight and with widely differing characteristics. For the purposes of this investigation only, the behavior of that portion of the asphalt which at room temperature was soluble in carbon tetrachloride and virtually insoluble in normal pentane was considered. The fraction in question is designated as bitumen.

The concentration of bitumen in the tank oil was determined by treating 1 volume of the oil with 9 volumes of n-pentane. The resulting liquid, which was a pale yellow color, appeared to be relatively free of bitumen. The yield of precipitate amounted to 0.0344 weight fraction of the tank-oil sample or about 10.25 lb of bitumen per barrel of tank oil.

The study of the separation of bitumen from mixtures of oil and gas at elevated pressures and temperatures was accomplished within a steel pressure vessel. This vessel has a volume of about 3.5 cu in. and is equipped with valves at both ends. The vessel was filled with the requisite quantity of oil and gas and brought to equilibrium by rotation normal to its principal axis. It was maintained at the temperature desired by immersion in a rapidly circulating air bath whose temperature was automatically controlled. After equilibrium was obtained, the pressur vessel was rotated for 30 min. about its longitudinal axis at a rate sufficient to produce a radial acceleration of approximately 1000 times that of gravity at the

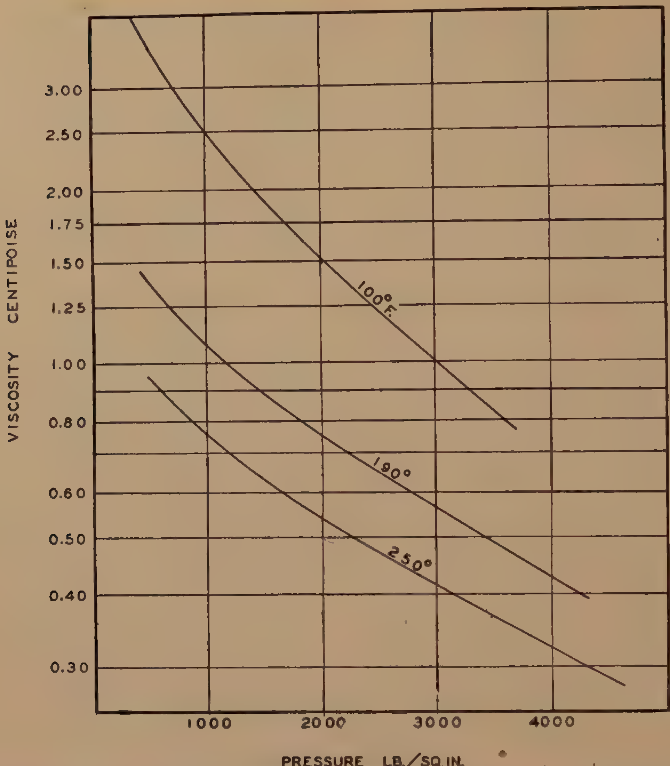

FIG 5—INFLUENCE OF PRESSURE AND TEMPERATURE UPON VISCOSITY OF BUBBLE-POINT LIQUID.

TABLE 8—*Properties of Bubble-point Liquid*

Pressure, Psia	100°F			190°F			250°F		
	Gas-oil Ratio Cu Ft per Bbl	Formation Volume	Viscosity, Centipoise	Gas-oil Ratio, Cu Ft per Bbl	Formation Volume	Viscosity, Centipoise	Gas-oil Ratio Cu Ft per Bbl	Formation Volume	Viscosity, Centipoise
600	222	1.132	3.24	188	1.186	1.31	168	1.219	0.90
800	269	1.148	2.82	229	1.200	1.18	204	1.234	0.82
1,000	319	1.164	2.50	271	1.216	1.07	241	1.249	0.76
1,250	382	1.186	2.18	325	1.237	0.97	291	1.270	0.69
1,500	450	1.210	1.92	382	1.261	0.89	344	1.294	0.63
1,750	520	1.238	1.71	441	1.287	0.82	398	1.320	0.58
2,000	596	1.270	1.52	502	1.316	0.76	456	1.348	0.54
2,250	672	1.307	1.36	568	1.347	0.70	515	1.380	0.51
2,500	754	1.349	1.22	637	1.380	0.65	577	1.414	0.47
3,000	940		1.00	788	1.456	0.56	707	1.489	0.42
3,500	1,160		0.82	950	1.546	0.49	844	1.572	0.37
4,000				1,125		0.42	990		0.32

inner surface of the vessel. The bitumen, being more dense than the liquid phase, was deposited on the walls of the pressure vessel. The liquid phase was displaced by introduction of mercury at the equilibrium pressure. Subsequent to the completion of the displacement, the mercury was drained from the equipment and all residual liquid was removed by washing with n-pentane through a sintered glass filter. The vessel and filter were weighed before and after removing the precipitated bitumen by solution in carbon tetrachloride. The change in weight of the assembly was recorded as the quantity of bitumen precipitated.

As a check on the results, the filtrate was evaporated and the bitumen residue was weighed. The change in weight of the pressure vessel and filter assembly agreed well with the weight of bitumen obtained as residue from the evaporation of the carbon tetrachloride solution. However, the loss in weight of the assembly was regarded as most representative and has been employed

TABLE 9—*Composition of Samples Used in Bitumen Studies*

Component	Trap Gas		Trap Liquid		Tank Oil	
	Mol Fraction	Weight Fraction	Mol Fraction	Weight Fraction	Mol Fraction	Weight[a] Fraction
Methane	0.8587	0.6980	0.0947	0.0096		
Ethane	0.0655	0.0998	0.0411	0.0078	0.0019	0.0003
Propane	0.0483	0.1079	0.0806	0.0225	0.0414	0.0094
Isobutane	0.0045	0.0132	0.0188	0.0069	0.0150	0.0045
n-Butane	0.0134	0.0395	0.0711	0.0261	0.0604	0.0181
Isopentane	0.0026	0.0095	0.0288	0.0131	0.0316	0.0118
n-Pentane	0.0026	0.0095	0.0293	0.0134	0.0329	0.0122
Hexanes	0.0016	0.0070	0.0628	0.0342	0.0810	0.0360
Heptanes and heavier	0.0028[b]	0.0156[c]	0.5728[d]	0.8664[e]	0.7358[d]	0.9077[e]
Average molecular weight	19.74		158.3		194.0	
Gas-oil ratio	Infinity		163.1		0	

[a] Gravity 35.1° API at 60°F and atmospheric pressure.
[b] Estimated average molecular weight, 110.
[c] Estimated gravity, 71° API at 60°F and atmospheric pressure.
[d] Average molecular weight indicated by freezing point lowering of benzene extrapolated to infinite dilution of solute, 239.4.
[e] Gravity 29.9° API at 60°F and atmospheric pressure.

TABLE 10—*Properties of the Heptanes-and-heavier Portion of the Trap-liquid Sample Used in Bitumen Studies*

Mol fraction of trap-liquid sample, 0.5728
Weight fraction of trap-liquid sample, 0.8664
Gravity at 60°F atmospheric pressure, 29.9° API
Kinematic viscosity in centistokes:
at 77°F, 11.92
at 100°F, 8.05
Viscosity-gravity factor, 0.852
Average molecular weight, 239.4

Cut Volume, Per Cent	Fractionation Analysis					
	Average Boiling Point Deg F	Gravity Deg API at 60°F	Kinematic Viscosity, Centistokes 77°F	Kinematic Viscosity, Centistokes 100°F	Viscosity Gravity Factor	Weight Fraction[a]
5	205	60.1	0.707	0.627	0.780	0.03529
5	286	51.2	0.893	0.780	0.813	0.03701
5	367	43.3	1.38	1.16	0.835	0.03868
5	440	39.7	2.55	2.02	0.833	0.03949
80		19.6	702.	188.5	0.879	0.71593

[a] Based upon entire trap-liquid sample.

TABLE 11—*Precipitation of Bitumen from Mixtures of Methane and Trap-liquid*

Bubble-point Pressure, Psia	230°F Weight Fraction Methane in Liquid Phase	Total Bitumen Precipitated,[a] Per Cent
500	0.010[b]	0.4
2,400	0.053	0.0
2,850	0.064	2.2
3,370	0.079	2.4
3,370	0.079	0.8
3,850	0.096	6.1
3,850	0.096	6.1
5,200[c]	0.186	27.8

[a] Total bitumen amounted to 0.0344 weight fraction of the tank-oil sample. This corresponds to 10.25 lb of bitumen per barrel of tank oil.
[b] Trap-liquid sample.
[c] Estimated bubble-point pressure.

to establish the results presented. Some difficulty was encountered in obtaining complete evaporation of carbon tetrachloride from solutions with bitumen and it is believed that this accounted for the uncertainty in the latter values.

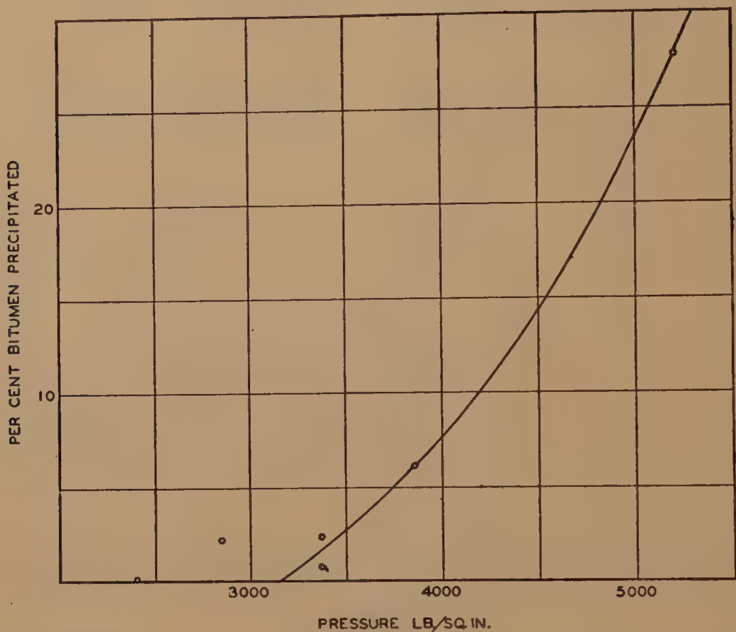

FIG 6—INFLUENCE OF BUBBLE-POINT PRESSURE UPON SEPARATION OF BITUMEN AT 230°F.

TABLE 12—*Composition of Samples of Gas-cap Material*

Component	Trap Gas		Trap Liquid		Tank Oil[a]	
	Mol Fraction	Weight Fraction	Mol Fraction	Weight Fraction	Mol Fraction	Weight Fraction
Methane	0.8251	0.6383	0.0982	0.0173		
Ethane	0.0819	0.1187	0.0413	0.0136	0.0081	0.0022
Propane	0.0457	0.0972	0.0699	0.0338	0.0343	0.0136
Isobutane	0.0071	0.0199	0.0392	0.0210	0.0122	0.0064
n-Butane	0.0142	0.0398	0.0721	0.0460	0.0532	0.0278
Isopentane	0.0039	0.0136	0.0424	0.0336	0.0463	0.0300
n-Pentane	0.0039	0.0136	0.0483	0.0382	0.0536	0.0348
Hexanes	0.0028	0.0116	0.1086	0.1026	0.1073	0.0831
Heptanes and heavier	0.0046[b]	0.0244[c]	0.4863[d]	0.6939[e]	0.6850[d]	0.8021[e]
Carbon dioxide	0.0108	0.0229				
Average molecular weight	20.74		91.22		111.20	
Gas-oil ratio	Infinity		354.6		0	

[a] Gravity, 59.0° API at 60°F and atmospheric pressure.
[b] Estimated average molecular weight, 110.
[c] Estimated gravity, 71° API at 60°F and atmospheric pressure.
[d] Average molecular weight indicated by freezing point lowering of benzene extrapolated to infinite dilution of the solute, 130.2.
[e] Gravity, 49.8° API at 60°F and atmospheric pressure.

The separation of bitumen at 230°F was studied for a number of methane-oil mixtures of compositions yielding bubble-point pressures varying from 2850 to 5200 psi. The yields of bitumen at pressures below 3370 psi were too small to be detected by

TABLE 13—*Properties of Heptanes-and-heavier Portion of Gas Cap Trap-liquid Sample*

Mol fraction of trap liquid, 0.4863
Weight fraction of trap liquid, 0.6939
Gravity at 60°F atmospheric pressure, 49.8° API
Kinematic viscosity, in centistokes:
at 77°F, 1.20
at 100°F, 1.03
Viscosity-gravity factor, 0.806
Average molecular weight, 130.2

Cut Volume, Per Cent	Average Boiling Point Deg F	Gravity Deg API at 60°F	Kinematic Viscosity, Centistokes 77°F	100°F	Viscosity Gravity Factor	Weight Fraction[a]
10	186	59.1	0.667	0.595	0.789	0.06586
10	205	58.8	0.760	0.690	0.782	0.06596
10	220	57.1	0.815	0.730	0.787	0.06656
10	242	55.3	0.847	0.747	0.794	0.06720
10	267	52.8	0.935	0.792	0.804	0.06811
10	293	50.0	1.005	0.875	0.815	0.06916
10	329	47.4	1.197	1.027	0.818	0.07016
10	378	44.2	1.592	1.30	0.826	0.07145
20		36.5	4.36	3.25	0.836	0.14944

[a] Based upon entire trap-liquid sample.

TABLE 14—*Composition of the Experimentally Studied Mixtures of Gas-cap Material*

Component	Weight Fraction Trap Gas 0.6334: Mol Fraction	0.6334: Weight Fraction	0.7194[a]: Mol Fraction	0.7194[a]: Weight Fraction
Methane	0.7406	0.4106	0.7660	0.4640
Ethane	0.0772	0.0802	0.0786	0.0892
Propane	0.0485	0.0739	0.0477	0.0794
Isobutane	0.0101	0.0203	0.0092	0.0202
n-Butane	0.0209	0.0421	0.0189	0.0415
Isopentane	0.0084	0.0209	0.0070	0.0192
n-Pentane	0.0091	0.0226	0.0075	0.0205
Hexanes	0.0151	0.0450	0.0114	0.0372
Heptanes and heavier	0.0606	0.2699	0.0438	0.2123
Carbon dioxide	0.0095	0.0145	0.0099	0.0165
Average molecular weight	28.93		26.48	
Gas-oil ratio	9,783		14,344	

[a] Corresponds very nearly to the well-production mixture.

the techniques employed. In the mixture containing 0.186 weight fraction methane, for which the bubble-point pressure was approximately 5200 psi, more than one fourth of the total bitumen present in the original trap samples was precipitated. The results are recorded in Table 11 and illustrated in Fig 6.

Behavior of Gas-cap Material

In contrast to the low gas-oil ratios observed for production from the black oil zones of the reservoir, the gas-oil ratio obtained for the wells producing from the gas cap was about 15,000 cu ft per barrel. The analyses of the trap-gas, trap-liquid and tank-oil samples taken from a well producing from the gas cap are given in Table 12. The properties of the heptanes-and-heavier portion of the trap liquid are recorded in Table 13. It is of interest to compare the analyses of the samples reported in Tables 1, 9 and 12 which indicate similarity in the relative proportions of the components for corresponding samples produced from different parts of the reservoir. It appears that the relative distribution of the more volatile hydrocarbons in the gas and liquid phases from the surface separators is relatively invariant regardless of whether the materials are produced from the black oil zone or the gas cap of the reservoir.

Procedure and Results

Two mixtures of trap liquid and trap gas from the gas cap were studied experimentally using the same volumetric apparatus employed for the investigation of the black oil samples. The quantity of liquid phase present at heterogeneous states of the system was determined by use of a "hot wire" technique which has been described.[6] The movable electric contacts which served to detect the elevation of the mercury hydrocarbon interface in the equilibrium cell were also equipped with a

TABLE 15—*Volumetric Behavior of the Experimentally Studied Mixtures of Gas-cap Material*

Weight fraction trap gas, 0.6334
Gas-oil ratio, 9,783 cu ft per bbl

Pressure, Psia	Specific Volume, Cu Ft per Lb	Liquid Volume, Cu Ft per Lb	Formation Volume	Liquid Formation Volume
100°F				
R.D.P.	(3,300)[a] 0.04523	0	6.606	0
600	0.2784	0.00863	40.65	1.260
800	0.20142	0.00930	29.42	1.358
1,000	0.15599	0.00989	22.780	1.444
1,250	0.12022	0.01053	17.557	1.538
1,500	0.09716	0.01105	14.190	1.614
1,750	0.08136	0.01146	11.882	1.674
2,000	0.07013	0.01176	10.242	1.717
2,250	0.06191	0.01184	9.042	1.729
2,500	0.05586	0.01158	8.157	1.691
2,750	0.05137	0.01074	7.502	1.568
3,000	0.04806	0.00845	7.019	1.234
3,250	0.04565	0.00220	6.667	0.321
3,500	0.04414		6.446	
3,750	0.04303		6.284	
4,000	0.04207		6.145	
4,250	0.04127		6.027	
4,500	0.04052		5.918	
4,750	0.03986		5.821	
5,000	0.03926		5.733	
190°F				
R.D.P.	(3,494) 0.05543	0	8.095	0
600	0.3508	0.00628	51.24	0.917
800	0.2562	0.00676	37.42	0.987
1,000	0.20049	0.00717	29.28	1.047
1,250	0.15681	0.00760	22.901	1.110
1,500	0.12842	0.00792	18.755	1.157
1,750	0.10855	0.00813	15.853	1.187
2,000	0.09401	0.00820	13.729	1.198
2,250	0.08304	0.00816	12.128	1.192
2,500	0.07458	0.00782	10.892	1.142
2,750	0.06795	0.00708	9.923	1.034
3,000	0.06270	0.00587	9.156	0.857
3,250	0.05865	0.00370	8.566	0.540
3,500	0.05535		8.084	
3,750	0.05308		7.752	
4,000	0.05118		7.474	
4,250	0.04962		7.247	
4,500	0.04828		7.051	
4,750	0.04705		6.871	
5,000	0.04595		6.710	
250°F				
R.D.P.	(3,385) 0.06527	0	9.532	0
600	0.3962	0.00425	57.87	0.621
800	0.2913	0.00470	42.55	0.686
1,000	0.22923	0.00508	33.48	0.742
1,250	0.18026	0.00544	26.33	0.794
1,500	0.14814	0.00568	21.635	0.830
1,750	0.12555	0.00577	18.335	0.843
2,000	0.10897	0.00570	15.914	0.832
2,250	0.09639	0.00545	14.077	0.796
2,500	0.08658	0.00497	12.645	0.726
2,750	0.07879	0.00416	11.506	0.608
3,000	0.07255	0.00292	10.596	0.426
3,250	0.06752	0.00116	9.861	0.169
3,500	0.06367		9.298	
3,750	0.06064		8.855	
4,000	0.05811		8.486	
4,250	0.05596		8.172	
4,500	0.05413		7.905	
4,750	0.05252		7.670	
5,000	0.05110		7.462	

TABLE 15—(*Continued*)

Weight fraction trap gas, 0.7194
Gas-oil ratio, 14,344 cu ft per bbl

Pressure, Psia	Specific Volume, Cu Ft per Lb	Liquid Volume, Cu Ft per Lb	Formation Volume	Liquid Formation Volume
100°F				
R.D.P.	(3,325) 0.04961	0	9.464	0
600	0.3150	0.00697	60.10	1.330
800	0.22765	0.00764	43.43	1.458
1,000	0.17585	0.00814	33.55	1.553
1,250	0.13509	0.00855	25.77	1.631
1,500	0.10877	0.00874	20.751	1.667
1,750	0.09070	0.00875	17.305	1.669
2,000	0.07788	0.00858	14.859	1.637
2,250	0.06851	0.00813	13.070	1.551
2,500	0.06168	0.00727	11.767	1.387
2,750	0.05668	0.00575	10.814	1.097
3,000	0.05302	0.00354	10.116	0.675
3,250	0.05030	0.00089	9.597	0.170
3,500	0.04850		9.253	
3,750	0.04709		8.984	
4,000	0.04585		8.748	
4,250	0.04481		8.550	
4,500	0.04388		8.372	
4,750	0.04307		8.217	
5,000	0.04232		8.075	
190°F				
R.D.P.	(3,420) 0.06250	0	11.924	0
600	0.3926	0.00406	74.91	0.775
800	0.2877	0.00448	54.89	0.855
1,000	0.22544	0.00481	43.01	0.918
1,250	0.17625	0.00509	33.63	0.971
1,500	0.14414	0.00524	27.50	1.000
1,750	0.12170	0.00523	23.219	0.998
2,000	0.10525	0.00505	20.080	0.963
2,250	0.09283	0.00470	17.711	0.897
2,500	0.08329	0.00415	15.891	0.792
2,750	0.07581	0.00338	14.464	0.645
3,000	0.06986	0.00234	13.329	0.446
3,250	0.06517	0.00100	12.433	0.191
3,500	0.06152		11.736	
3,750	0.05871		11.202	
4,000	0.05643		10.765	
4,250	0.05450		10.397	
4,500	0.05286		10.084	
4,750	0.05139		9.804	
5,000	0.05009		9.557	
250°F				
R.D.P.	(3,220) 0.07608	0	14.515	0
600	0.4433	0.00245	84.58	0.467
800	0.3263	0.00274	62.25	0.523
1,000	0.2568	0.00296	49.00	0.565
1,250	0.20195	0.00312	38.53	0.595
1,500	0.16597	0.00316	31.66	0.603
1,750	0.14068	0.00310	26.84	0.591
2,000	0.12207	0.00291	23.289	0.555
2,250	0.10787	0.00258	20.580	0.492
2,500	0.09692	0.00212	18.490	0.404
2,750	0.08816	0.00150	16.819	0.286
3,000	0.08116	0.00074	15.485	0.141
3,250	0.07547		14.398	
3,500	0.07107		13.559	
3,750	0.06741		12.861	
4,000	0.06433		12.274	
4,250	0.06173		11.778	
4,500	0.05952		11.355	
4,750	0.05760		10.989	
5,000	0.05587		10.659	

[a] Figures in parentheses represent retrograde dew-point (R.D.P.) pressures expressed in pounds per square inch absolute.

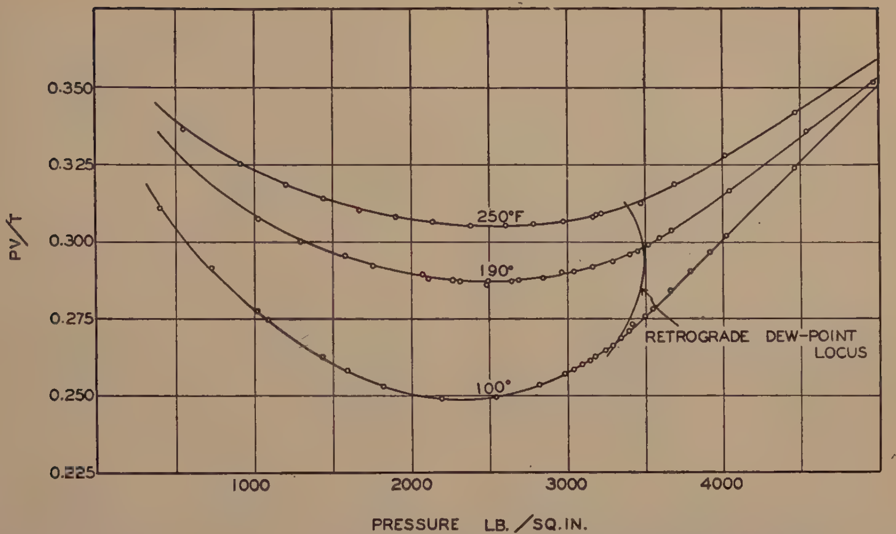

FIG 7—VOLUMETRIC BEHAVIOR OF GAS-CAP MATERIAL AT GAS-OIL RATIO OF 9783 CUBIC FEET PER BARREL.

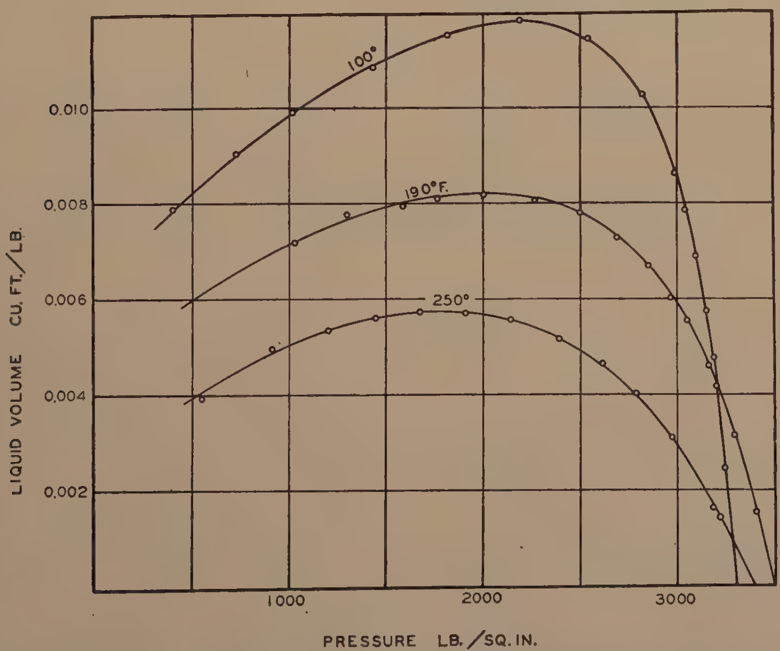

FIG 8—LIQUID VOLUME OF GAS-CAP MATERIAL AT GAS-OIL RATIO OF 9783 CUBIC FEET PER BARREL.

horizontal platinum wire about 0.004 in. in diameter. The wire was maintained at a temperature of 1°F above that of its surroundings by passing a current of approximately 0.2 amp through it. The temperature and consequently the resistance of the wire was a function of the thermal conductivity of the surrounding phase. The location of the gas-liquid interface was determined by noting the change in resistance of the platinum wire as it was moved vertically from one phase to the other. In general, the elevation of the gas-liquid interface could be determined within 0.002 in.

The compositions of the experimentally studied mixtures of gas-cap material are given in Table 14. The nature of the results obtained in the mixture having a gas-oil ratio of 9783 cu ft per barrel is shown in Fig 7 and 8. The volumetric data were smoothed and interpolated graphically to even values of pressure and the results are recorded in Table 15.

In the range of temperatures encompassed by this investigation, mixtures of naturally occurring hydrocarbons with gas-oil ratios greater than 5000 cu ft per barrel can generally be expected to exhibit retrograde phase behavior. The retrograde dew-point states in the present study were determined by the vanishing point of the liquid phase as pressure was increased by the isothermal decrease in volume. The change in volume of the liquid phase for a mixture of a gas-oil ratio of 9783 cu ft per barrel is shown in Fig 8.

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Revaporization of Butane and Pentane from Sand

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(New York Meeting, February 1948)

Abstract

A study of the behavior of retrograde condensation from gas mixtures was made in the presence and absence of sand in order to determine if the condensed liquid would revaporize in the presence of sand. Methane-butane and methane-pentane mixtures that would form liquids by retrograde condensation when produced from a constant volume cell were used.

The methane-butane mixtures of similar composition were produced by three different methods. The first two were charged into an empty cell and were produced in one case within a period of 9 hr and in the other within a period of 3 days. The third mixture was charged to a sand-packed cell and produced within a period of 9 hr. The curves relating composition of the produced gas to pressure obtained from these experiments show that equilibrium was maintained as long as liquid was condensing. However, during the portion of the pressure decline where the condensed liquid should be revaporizing, equilibrium was maintained only when the mixture was produced from the sand-packed cell.

The methane-pentane mixture is produced only in the presence of sand. The data obtained for this system also show that equilibrium is maintained at all times during the pressure decline.

These results indicate that revaporization is aided rather than prevented by the fact that the condensate "wets the sand."

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Introduction

The significance to the petroleum industry of the behavior of hydrocarbons in the retrograde region is becoming increasingly important because a large percentage of reservoirs being discovered today are of the gas-condensate type. The important characteristic of a gas-condensate reservoir is the retrograde condensation of a liquid phase throughout the reservoir if the pressure is allowed to decline. In order to prevent the loss of this retrograde liquid in some of these reservoirs, they are "cycled"; that is, the material produced from the reservoir is processed to remove the heavier hydrocarbons and the light fractions are returned to the reservoir to maintain the reservoir pressure. Another method of producing these reservoirs is pressure depletion. There are other methods but they are not in general use.

Although a large number of factors are involved in determining the optimum method of producing a reservoir, only the problem of whether the retrograde condensate resulting from pressure depletion will revaporize from sand at equilibrium conditions is considered in this paper. Also the data are limited to the methane-n-butane and the methane-n-pentane systems at 100°F and one type of sand.

Three types of tests were run in order to compare the revaporization of retrograde liquid formed in a cell with that formed in a sand-packed cell, and to establish the effect of time.

The results of tests presented in this paper indicate that both time and the presence of sand promote the revaporization of

the retrograde liquid at equilibrium conditions for the systems studied.

Method

A system composed of methane and n-butane or methane and n-pentane known to form liquid by retrograde condensation was charged to a steel cell at a pressure above its upper dew-point pressure. It was then held at this pressure and constant temperature for at least 24 hr in order to make certain that the composition was uniform within the cell. The system, then, was produced slowly from the top of the cell through a throttle valve into evacuated collecting flasks. The contents of the cell were not mixed by stirring or rocking the cell during the production period. As each flask was filled, the pressure decline within the cell was recorded and a sample of the gas from each flask was analyzed.

The rate of production or pressure decline was held nearly constant throughout each of the four tests; however, the rates were different for two of the tests to ascertain the effect of time. The other variable studied was the presence and absence of sand which was packed in the steel cell for two of the tests.

Table 1—*Data for the Pressure Depletion of Methane-n-Butane System from an Unpacked Constant Volume Cell at 100°F at a Rate Requiring 9 Hours*

Pressure in Constant Volume Cell, Psia		Average Composition of Produced Gas Data				
		Molecular Weight Data				
		Density Determination				
Initial	Final	Pressure, Inches Hg	Temperature, Degree F	Compressibility Factor	Molecular Weight	Mol Fraction CH_4
2,255	2,230	24.02	86.0	0.993	23.66	0.8189
2,130	2,085	24.08	85.8	0.993	23.79	0.8158
2,035	2,000	24.18	85.0	0.993	23.68	0.8184
1,955	1,915	24.06	86.1	0.993	23.78	0.8161
1,875	1,845	27.02	86.2	0.992	23.89	0.8135
1,815	1,785	27.05	87.5	0.992	23.23	0.8291
1,760	1,735	27.26	87.4	0.993	22.84	0.8384
1,700	1,670	26.92	87.2	0.993	22.90	0.8370
1,640	1,615	27.03	87.4	0.993	22.48	0.8470
1,575	1,545	26.91	87.3	0.994	22.12	0.8555
1,515	1,480	27.00	88.3	0.994	21.67	0.8662
1,450	1,410	27.06	88.4	0.994	21.67	0.8662
1,385	1,340	27.07	89.5	0.994	21.27	0.8757
1,300	1,275	26.55	90.0	0.994	21.32	0.8745
1,240	1,200	26.98	90.0	0.994	21.34	0.8740
1,155	1,120	27.02	90.1	0.994	21.18	0.8778
1,070	1,045	27.04	90.4	0.994	21.14	0.8798
1,005	975	26.99	90.3	0.994	21.28	0.8755
920	880	27.02	90.2	0.994	21.57	0.8686
845	805	27.09	90.1	0.994	21.74	0.8645
750	715	27.07	90.8	0.994	21.83	0.8624
665	620	27.09	91.4	0.994	21.74	0.8645
575	525	27.04	91.3	0.994	21.59	0.8681
488	425	26.97	91.5	0.994	21.61	0.8676
385	330	27.04	92.0	0.994	21.65	0.8667
285	240	28.48	92.0	0.994	22.34	0.8503
240	185	26.85	91.9	0.994	22.29	0.8515
135	80	26.95	91.9	0.992	24.66	0.7952
80	55	26.86	92.3	0.990	30.49	0.6568
55	40	26.69	92.0	0.975	48.87	0.2198
40	15	26.35	92.3	0.968	58.14	0.0000

TABLE 2—*Data for the Pressure Depletion of Methane-n-Butane System from an Unpacked Constant Volume Cell at 100°F at a Rate Requiring 3 Days*

Pressure in Constant Volume Cell, Psia		Average Composition of Produced Gas Data				
		Molecular Weight Data				
		Density Determination			Molecular Weight	Mol Fraction CH_4
Initial	Final	Pressure, Inches Hg	Temperature, Degree F	Compressibility Factor		
2,245	2,200	25.96	84.3	0.993	24.13	0.8031
2,200	2,145	25.94	86.0	0.993	24.24	0.8051
2,145	2,095	26.03	88.1	0.993	24.36	0.8023
2,095	2,045	26.76	90.0	0.993	24.40	0.8017
2,045	2,000	25.99	91.0	0.993	24.58	0.7971
2,000	1,955	26.25	92.0	0.993	24.71	0.7940
1,955	1,915	26.62	92.9	0.993	24.69	0.7949
1,915	1,870	29.96	93.6	0.991	24.71	0.7940
1,870	1,840	26.23	93.8	0.993	24.66	0.7952
1,840	1,810	26.16	94.0	0.993	24.43	0.8001
1,810	1,785	25.93	94.2	0.993	24.23	0.8054
1,785	1,755	26.24	93.9	0.993	23.86	0.8142
1,755	1,725	26.05	93.0	0.994	23.35	0.8263
1,725	1,695	25.94	92.5	0.994	23.30	0.8274
1,695	1,665	25.64	91.6	0.994	23.32	0.8269
1,665	1,640	25.99	90.2	0.994	22.61	0.8438
1,640	1,605	25.81	89.8	0.994	22.74	0.8408
1,605	1,575	26.01	88.5	0.994	22.17	0.8540
1,575	1,545	25.84	88.0	0.994	22.46	0.8475
1,545	1,510	25.89	86.8	0.994	22.20	0.8532
1,510	1,475	25.92	86.0	0.994	22.14	0.8550
1,475	1,445	26.09	85.6	0.994	21.73	0.8647
1,445	1,410	23.26	84.6	0.995	21.89	0.8664
1,410	1,375	25.89	84.3	0.994	21.66	0.8663
1,375	1,345	25.95	84.0	0.995	21.34	0.8740
1,345	1,305	26.00	84.0	0.995	21.33	0.8745
1,305	1,275	26.00	86.0	0.995	21.43	0.8718
1,275	1,230	26.64	88.0	0.995	21.45	0.8714
1,230	1,195	26.58	88.8	0.995	21.35	0.8738
1,195	1,150	25.94	90.0	0.995	21.42	0.8722
1,150	1,100	26.50	92.0	0.995	21.53	0.8695
1,100	1,060	25.96	92.4	0.995	21.60	0.8679
1,060	1,015	25.86	92.7	0.995	21.36	0.8735
1,015	975	25.88	93.7	0.994	21.71	0.8653
975	930	26.22	93.7	0.994	21.55	0.8692
930	890	25.86	93.7	0.994	21.63	0.8671
890	860	25.64	93.0	0.994	21.67	0.8661
860	815	25.91	92.6	0.994	21.68	0.8660
815	770	25.97	92.1	0.994	21.66	0.8664
770	720	25.90	91.5	0.994	21.36	0.8676
720	670	25.78	90.4	0.994	21.79	0.8632
670	630	25.93	88.7	0.994	22.37	0.8614
630	585	25.83	87.5	0.994	22.32	0.8621
585	530	25.91	86.2	0.994	21.78	0.8659
530	495	25.94	86.0	0.994	21.99	0.8634
495	450	25.88	85.7	0.994	21.95	0.8596
450	400	25.95	85.7	0.994	22.13	0.8552
400	350	25.94	85.2	0.994	22.34	0.8502
350	305	25.90	84.6	0.994	22.73	0.8409
305	255	25.94	85.8	0.994	23.41	0.8238
255	210	25.91	88.2	0.993	24.79	0.7945
210	165	25.91	89.6	0.992	26.87	0.7421
165	125	27.54	91.0	0.990	29.83	0.6822
125	90	28.60	93.8	0.986	35.36	0.5409
90	70	25.79	94.2	0.978	46.12	0.2852
70	60	25.79	93.8	0.974	53.88	0.1003
60	35	25.78	93.7	0.970	57.43	0.0163

TABLE 3—*Data for the Pressure Depletion of a Methane-n-Butane System from a Sand Packed Constant Volume Cell at 100°F at a Rate Requiring 9 Hours*

Pressure in Constant Volume Cell, Psia		Average Composition of Produced Gas Data				
		Molecular Weight Data				
		Density Determination			Molecular Weight	Mol Fraction CH_4
Initial	Final	Pressure, Inches Hg	Temperature, Degree F	Compressibility Factor		
1,975	1,880	26.12	89.4	0.992	24.88	0.7899
1,880	1,810	26.07	89.4	0.993	24.42	0.8007
1,810	1,740	26.12	90.3	0.993	23.48	0.8231
1,740	1,670	26.15	90.5	0.993	23.35	0.8264
1,670	1,580	26.13	90.5	0.994	22.83	0.8387
1,580	1,510	26.02	91.0	0.994	22.59	0.8431
1,510	1,435	26.21	91.9	0.994	22.40	0.8490
1,435	1,340	26.07	92.3	0.994	22.19	0.8538
1,340	1,250	26.02	92.7	0.995	21.76	0.8642
1,250	1,155	26.06	92.9	0.995	21.74	0.8644
1,155	1,055	25.97	92.7	0.995	21.53	0.8695
1,055	950	25.95	92.7	0.995	21.57	0.8687
950	860	26.00	93.0	0.995	21.80	0.8633
860	750	26.01	92.7	0.995	21.81	0.8630
750	635	26.08	92.0	0.995	21.91	0.8600
635	525	26.03	92.4	0.994	22.60	0.8446
525	415	26.01	92.7	0.993	23.33	0.8261
415	305	26.04	92.5	0.993	24.71	0.7940
305	205	25.99	92.4	0.990	27.37	0.7305
205	110	26.90	92.4	0.987	33.43	0.5836
110	60	26.84	92.2	0.978	46.31	0.2688
60	15	21.72	92.0	0.972	57.65	0.0112

TABLE 4—*Data for the Pressure Depletion of a Methane-n-Butane System from a Sand Packed Constant Volume Cell at 100°F at a Rate Requiring 9 Hours*

Pressure in C Constant Volume Cell, Psia		Average Composition of Produced Gas Data				
		Molecular Weight Data				
		Density Determination			Molecular Weight	Mol Fraction CH_4
Initial	Final	Pressure, Inches Hg	Temperature, Degree F	Compressibility Factor		
2,215	2,120	28.64	100.0	0.996	20.38	0.9227
2,045	1,960	28.16	100.0	0.996	20.00	0.9294
1,880	1,810	29.07	100.0	0.996	19.76	0.9338
1,730	1,650	29.02	100.0	0.996	19.31	0.9417
1,580	1,490	28.88	100.0	0.997	19.04	0.9465
1,410	1,320	28.88	100.0	0.997	18.82	0.9503
1,240	1,145	28.96	100.0	0.997	18.67	0.9532
1,060	965	28.79	100.0	0.997	18.53	0.9557
880	780	29.19	100.0	0.997	18.52	0.9540
785	580	28.59	100.0	0.997	18.66	0.9534
490	385	28.82	100.0	0.997	19.10	0.9456
290	180	28.80	100.0	0.996	20.81	0.9150
180	80	29.04	100.0	0.995	23.56	0.8660

The analytical method employed was similar to that described by Sage, Hicks, and Lacey[1] whose data are compared with those presented in this paper. The com-

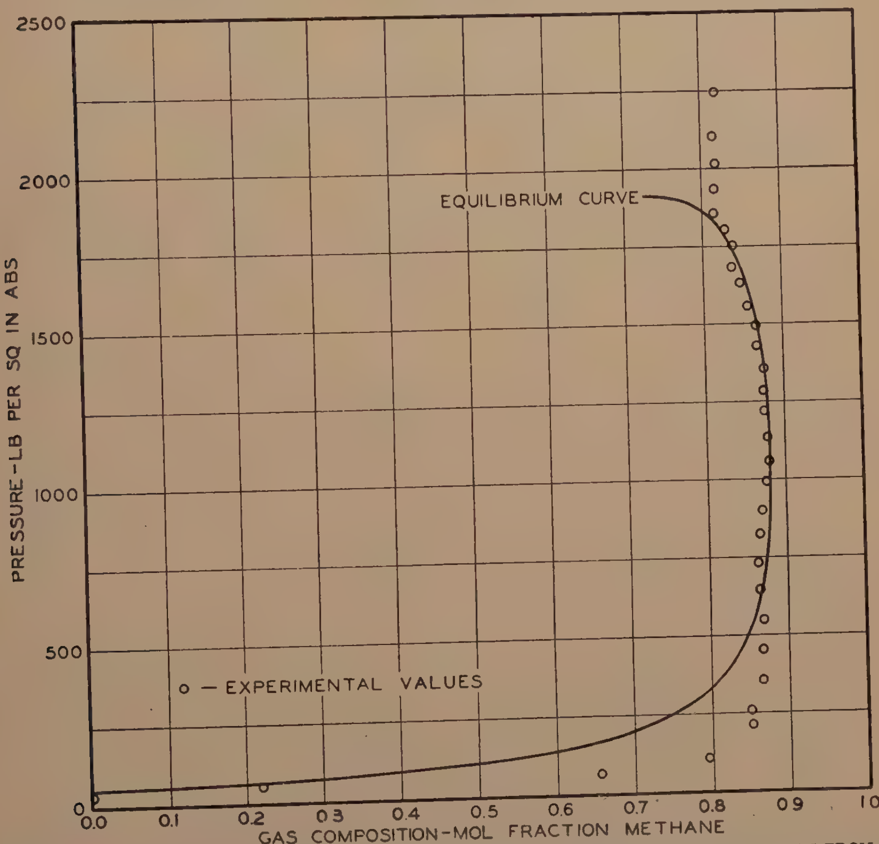

FIG 1—COMPARISON OF DATA FOR PRESSURE DEPLETION OF METHANE-N-BUTANE SYSTEM FROM UNPACKED CONSTANT VOLUME CELL AT 100°F AT RATE REQUIRING 9 HR WITH EQUILIBRIUM VALUES.

position of the produced gas was determined from its density which was measured by the change in weight of a glass bulb weighed against an identical tare. The deviation from ideal gas-law factors used to compute the compositions from the density measurements were estimated from the data of Sage, Hicks, and Lacey;[1] McKetta and Katz;[2] and Sage, Reamer, Olds, and Lacey.[3]

The uncertainty of the composition determinations is probably less than 0.003 mol fraction. The pressures, which were measured by means of a steel Bourdon tube gauge calibrated against a dead weight tester, are within 5 psi. The temperatures were determined with a mercury bulb thermometer which was calibrated against a U.S. Bureau of Standards calibrated thermometer and are within 0.05°F.

MATERIALS

All the hydrocarbons used were Phillips Petroleum Company Pure Grade having a guaranteed minimum purity of 99 mol pct.

[1] References are at the end of the paper.

The sand used to pack the cell was composed of well-rounded and well-sorted quartz grains of St. Peter sandstone from Ottawa, Ill., also known as standard different rates. The other methane-n-butane mixture was charged into the same steel cell packed with sand. The methane-n-pentane mixture also was produced from

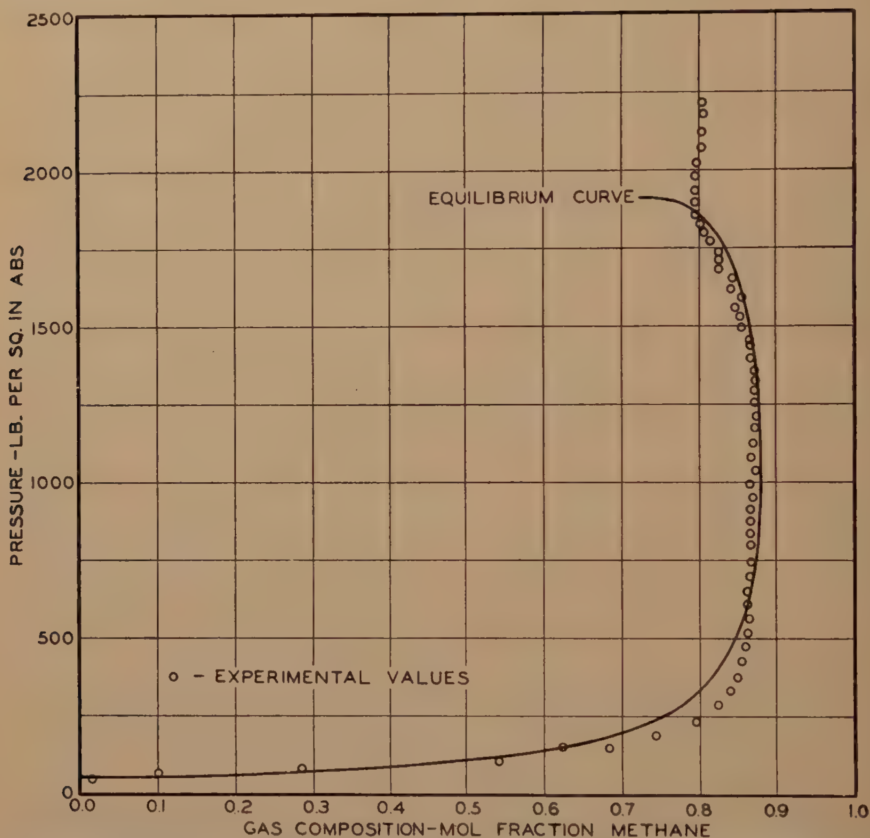

FIG 2—COMPARISON OF DATA FOR PRESSURE DEPLETION OF METHANE-N-BUTANE SYSTEM FROM UNPACKED CONSTANT VOLUME CELL AT 100°F AT RATE REQUIRING 3 DAYS WITH EQUILIBRIUM VALUES.

Ottawa sand, described in ASTM code 2170.

EXPERIMENTAL RESULTS

Data are presented in Table 1 to 4 and Fig 1 to 4 on the production of three methane-n-butane mixtures of approximately the same composition and one methane-n-pentane mixture. Two of the methane-n-butane mixtures were charged into the empty steel cell and produced at the sand-packed cell. The rates of production were comparable for all the tests except one of two charged to the unpacked cell.

Table 1 and Fig 1 contain the data from the experiment in which a methane-n-butane system was produced from an unpacked cell at a rate of pressure decline of approximately 240 psi per hour. When the pressure of the system was declined to the upper dew-point pressure, the

relative amount of methane in the produced gas increased indicating the formation of liquid phase within the cell. This liquid phase, having a greater density, collected position of the gas remained almost constant until the pressure approached the vapor pressure of n-butane, when the n-butane content of the produced gas

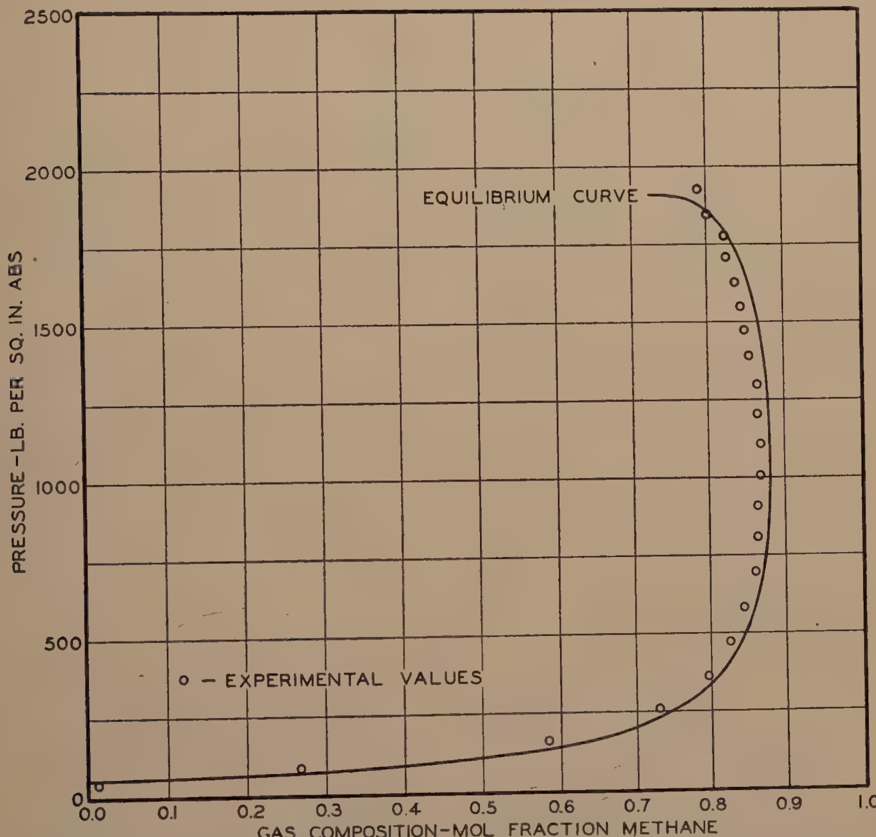

FIG 3—COMPARISON OF DATA FOR PRESSURE DEPLETION OF METHANE-N-BUTANE SYSTEM FROM SAND-PACKED CONSTANT VOLUME CELL AT 100°F AT RATE REQUIRING 9 HR WITH EQUILIBRIUM VALUES.

at the bottom of the cell, and, therefore, was not produced with the gas phase. The relative amount of methane in the produced gas continued to increase, as would be predicted by the equilibrium data of Sage, Hicks, and Lacey,[1] until the equilibrium data indicate that the relative amount of butane in the produced gas should increase because of the vaporization of the condensed liquid.

From this point on however, the composition of the gas ... increased very rapidly. This denotes that the condensed liquid is not revaporizing at equilibrium conditions.

The other methane-n-butane mixtuer charged to the empty cell was produced at a rate of pressure decline of approximately 40 psi per hour. The results obtained were similar to those described above when the rate of pressure decline was 6 times greater. However, in the region where the retrograde liquid would revaporize if the system

were in equilibrium the n-butane content of the produced gas more nearly approached the equilibrium values than those presented in the above case. This produced only from the sand-packed cell. The results are comparable with those obtained by producing the methane-n-butane mixture in the presence of sand.

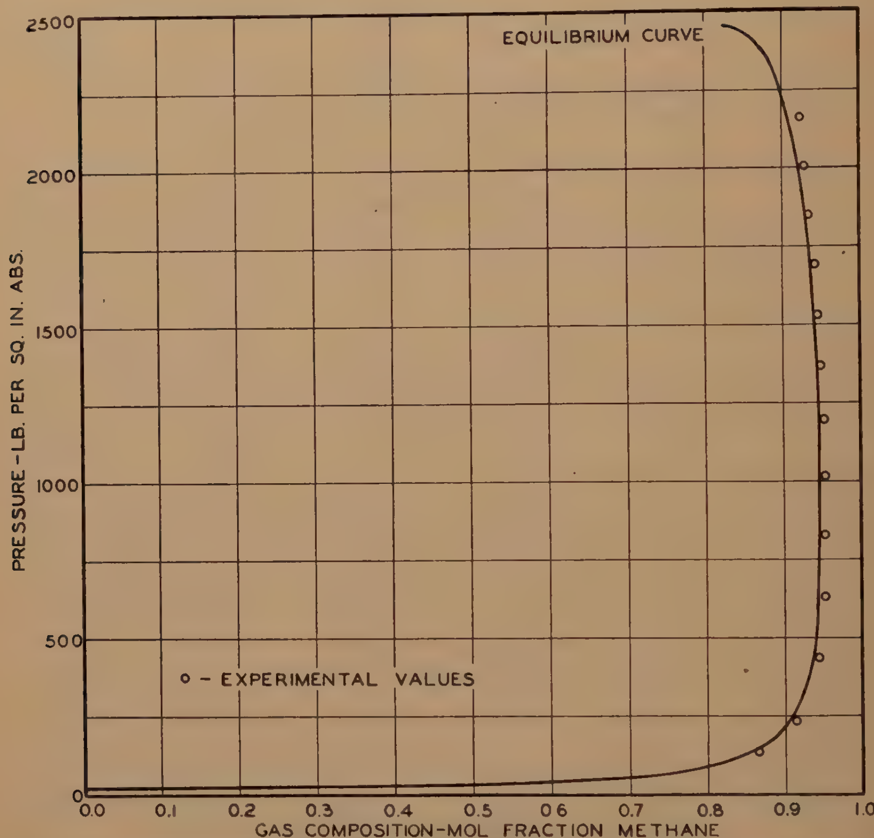

FIG 4—COMPARISON OF DATA FOR PRESSURE DEPLETION OF METHANE-N-PENTANE SYSTEM FROM SAND-PACKED CONSTANT VOLUME CELL AT 100°F AT RATE REQUIRING 9 HR WITH EQUILIBRIUM VALUES.

shows that more revaporization was taking place.

The data from the production of the methane-n-butane mixture in the presence of sand show that the composition of the produced gas approached that which would be predicted by equilibrium data throughout the pressure decline, thus indicating that the retrograde liquid is revaporizing at equilibrium conditions.

The methane-n-pentane mixture was

The results of the two experiments with an unpacked cell show that equilibrium was more nearly approached when revaporization was taking place during the experiment requiring 3 days than in the one requiring 9 hr. Therefore, as these time periods are relatively short, the very long time required to produce a natural reservoir should be sufficient to establish equilibrium for these systems if time were the only factor under consideration. How-

ever, the procedure normally used to test a naturally occurring system for retrograde "loss" compare very well with that of the experiment completed in 9 hr with an unpacked cell, except that production is stopped between samples and equilibrium is re-established by mixing. The data presented in this paper indicate that the composition of the gas remains constant between mixing periods. Thus the apparent retrograde loss determined in this manner will not check that which would be found if equilibrium had been maintained at all times. This error will be reduced to a negligible amount if the withdrawals are small between stirring periods.

The results of the test using methane-n-butane in the presence of sand show that the sand is considerably more effective in maintaining equilibrium during the production than the time periods employed. This may be accounted for by the difference in liquid-vapor surface area formed in the two cases. When the cell was not packed with sand, all of the liquid collected in the bottom of the cell forming a small liquid-vapor interface. However, when the cell was packed with sand, the liquid condensed on the surfaces of the sand with little or no drainage to the bottom of the cell. Thus, a large liquid-vapor surface was formed. The establishment of equilibrium depends upon mass transfer between the liquid and vapor phases, and the rate of mass transfer is directly proportional to the surface area. Therefore, the results obtained with the use of a sand-packed cell could be expected to be nearer to equilibrium than those obtained with the unpacked cell at approximately the same rate of pressure decline.

Nothing is said in the previous discussion about adsorption which could affect the results. Adsorption, as believed by many, would prevent retrograde condensate from revaporizing from the sand. The data presented in this paper do not confirm this but show that the adsorption does not take place or is too small to be effective.

In the previous discussion the systems were assumed to be at equilibrium if the results check within ± 0.01 mol fraction of the data presented by Sage, Hicks, and Lacey.[1] All of the values obtained for the methane-n-butane mixtures above 500 psia are about 0.01 mol fraction higher in n-butane content. McKetta and Katz[2] were unable to check the data of Sage, Hicks, and Lacey above about 500 psia at 100°F. As the data of McKetta and Katz check the results presented in this paper within 0.003 mol fraction, the above assumption appears to be valid. The data of Sage, Hicks, and Lacey are used for comparison because they are complete for the two-phase regions studied.

It is well known that the greater the difference between molecular weights of the hydrocarbons in a mixture, the more difficult it is to establish equilibrium for the system. Consequently the results of producing a methane-n-pentane mixture from an unpacked cell could be expected to be further from equilibrium than those obtained under comparable conditions with the methane-n-butane mixture. As the results of producing the methane-n-pentane mixture from the sand-packed cell check those obtained with the methane-n-butane mixture under these conditions, the same conclusions that are drawn from the methane-n-butane data can be drawn for the methane-n-pentane data without obtaining the data for producing this system from an unpacked cell.

Conclusions

The data presented on the methane-n-butane and the methane-n-pentane systems show that the P-V-T vapor-liquid equilibrium values are not affected by the presence of the sand. As the fundamental values for these systems hold in the presence of sand, it appears reasonable to assume that the fundamental values for

more complex systems will not be affected either. If this assumption is correct, revaporization of retrograde condensate as indicated by vapor-liquid equilibrium data is not affected by the presence of sand.

Equilibrium is maintained in the presence of sand even at the fast rates of pressure decline usually employed in the laboratory studies of these systems. Therefore, sand-packed cells could be used to facilitate the experimental determination of isothermal retrograde condensation curves.

References

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2. J. J. McKetta: PhD Dissertation, University of Michigan (1946).
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Effect of Permeability Stratification in Cycling Operations

By Morris Muskat,* Member AIME

(Dallas and Los Angeles Meetings, October 1948)

Abstract

A general theory has been developed for the effect of permeability stratification on the efficiency of the gas-injection phase of cycling operations. It has been applied to three special types of permeability variation; namely, exponential, probability, and linear. In the case of the exponential permeability distribution the effect of areal pattern sweep efficiency was also taken into account.

The exponential permeability distribution can be characterized by the ratio of the maximum to minimum permeability, which has been termed the stratification constant. Curves were calculated for the variation in total wet gas recovery and total gas throughflow, to give that recovery to various abandonment limits of the wet gas content in the produced gas, as a function of the stratification constant. The cumulative wet gas recovery decreases monotonically as the stratification constant increases and is generally higher at the lower values of the wet gas content abandonment limits. The total gas throughflow first rises to a maximum as the stratification increases, and then ultimately declines. The effect of the areal sweep pattern efficiency is relatively minor as compared to that of the stratification constant, except in the region of low values of the latter where the formation is substantially uniform.

The probability distribution can be characterized by a "variation" parameter varying from 0 to 1 as the formation changes from strict uniformity to extreme variability. The curves of total wet gas recovery and total gas throughflow to different abandonment limits of wet gas content versus the variation parameter have the same general characteristics as for the exponential permeability distribution.

In the linear permeability distribution the ratio of maximum to minimum permeability also serves as a stratification constant index defining the distribution. The curves of total wet gas recovery and gas throughflow to fixed abandonment limits versus the stratification constant are similar to those for the exponential permeability distribution. However, for the higher values of the stratification constant the recoveries and throughflows do not asymptotically fall to 0 as in the latter, but approach constant values determined by the abandonment limit of wet gas content in the produced gas.

Introduction

It is becoming generally recognized that one of the most important factors determining the economic feasibility of cycling operations is the areal continuity and permeability distribution of the producing formation. While the effects of areal variations in permeability, porosity, thickness, and well pattern on the sweep efficiency can be evaluated by electrical model studies,[1] those due to permeability stratification require separate treatment. Several studies have been reported[2,3] on the influence of permeability variations on the wet gas recovery by cycling. In these, however, discontinuous permeability variations either have been assumed explicitly, or the analysis has been carried through as if they were discontinuous. While, in fact, the actual permeability profiles will undoubtedly be discontinuous, recent develop-

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* Gulf Research and Development Co., Pittsburgh, Pa.

1 References are at the end of the paper.

ments[4] in the statistical analysis of such profiles suggest that often they can be approximated by continuous functions. Such representations are especially convenient because they can be characterized by simple parameters in the basic functional expressions. The sweep efficiency analysis for several such basic types of permeability functions will be given in this paper.

As in all analytical studies of the type to be considered here, the composite producing formation being cycled will be treated as a parallel superposition of the individual strata of different permeability and thickness.* Each, however, will be assumed to have constant effective permeability, thickness, and net porosity over the producing area. It will be assumed further that all the wells, both production and injection, completely penetrate all strata. Accordingly, there will be no crossflow as long as differences in mobility and density of the injected and displaced fluids are neglected, and the various strata can be re-arranged so as to give monotonic variations in the permeability with the depth.

General Theory

Assuming the actual formation strata to be rearranged to give a monotonic continuous permeability distribution $k(z)$,* where z is measured along the well bore from the layer of lowest permeability, the rate of reservoir throughflow, per unit thickness in the lamina at depth z, may be expressed as:

$$Q(z) = ck(z) \qquad [1]$$

where c is a constant determined by the areal geometry of the reservoir, the well distribution, and the relative injection and producing rates. Now for a fixed cycling pattern and operating plan the composition of the produced gas in a uniform zone will be a function only of the total gas throughflow,† expressed as a fraction of the hydrocarbon pore volume. The rate of wet gas production from a unit thickness lamina at z at the time t will therefore be:

$$Q_w(z,t) = ck(z)F\left(\frac{ctk(z)}{A\bar{f}(z)}\right) \qquad [2]$$

where F denotes the variation of the wet gas fraction in the produced gas with the total gas throughflow for a uniform stratum, as determined by the well pattern and flux distribution, and its argument is the cumulative gas throughflow divided by the displaceable hydrocarbon volume available at z. A is the reservoir area, and $\bar{f}(z)$ the net hydrocarbon displacement porosity‡ in the

* This idealized representation of perfect stratification and areal continuity will, of course, never occur in practice and lead to maximum by-passing effects. In actual reservoirs, where the permeability will vary laterally, with its own statistical distribution, at least the initial breakthrough sweep efficiencies will be higher than calculated here. The analytical treatment of such heterogeneous systems, however, would be extremely difficult even for the simplest types of permeability distributions. It is also assumed throughout this paper that gross steady state conditions obtain during the cycling operations in the sense that the rate of total gas injection, in reservoir measure, is the same as the rate of total gas withdrawals. This implies that make-up gas is provided to replace the losses due to shrinkage and use of some of the produced gas for fuel.

* In the formal theory of this section the re-arrangement is actually assumed to provide a monotonic variation of $k(z)/\bar{f}(z)$. In the treatment of specific cases, however, as will be done in the following sections, it is necessary to specify $k(z)$ and $\bar{f}(z)$ separately, and for convenience the latter will be taken as constant.

† In actual practice, of course, the effective well pattern and rate distributions will change during the cycling life as producing wells are abandoned or converted to injection wells when their wet gas production becomes too low. While such effects could be formally included by proper choice of the function F, no such detailed interpretation will be attempted here.

‡ $\bar{f}$ represents the net porosity occupied by the invading fluid, and may be taken simply as the net hydrocarbon porosity, since there is little evidence of an important degree of microscopic mixing in gas displacement processes.

rearranged system defined by $\bar{k}(z)$. For brevity the argument of F will be denoted by u. The fraction of wet gas in the total effluent from the stratified formation, at the time t, will then be:

$$R_w(t) = \frac{\int_0^H k(z)F(u)\,dz}{\int_0^H k(z)\,dz}; \qquad u = \frac{ctk(z)}{A\bar{f}(z)} \qquad [3]$$

where H is the total thickness of the permeable pay.

Eq 3 defines the composition history of the production as a function of time. It can be related implicitly to the total fractional reservoir sweep by noting that the total wet gas produced at time t is:

$$\left.\begin{aligned} \bar{Q}_w(t) &= \int_0^t dt \int_0^H Q_w(z,t)dz \\ &= c\int_0^t dt \int_0^H k(z)F(u)dz \\ &= Q_o \int_0^t R_w(t)dt \end{aligned}\right\} \qquad [4]$$

where Q_o is the throughflow rate, assumed constant, from the composite formation. The fractional reservoir sweep is, then,

$$\bar{V}(t) = \frac{\bar{Q}_w(t)}{A\int_0^H \bar{f}dz} \qquad [5]$$

To proceed further, it is noted from the definition of the function F, and its argument u, that while it will vary with each cycling pattern, it must always satisfy the relations:

$$\int_0^\infty F(u)du = 1; \qquad \int_S^\infty F(u)du = 1 - S; \qquad F(u) = 1; \qquad u \leq S \qquad [6]$$

where S is the areal sweep efficiency, or the fractional displaceable reservoir volume of a uniform stratum swept out by the time of first gas breakthrough. Then if the permeability range in the producing formation has a nonvanishing lower bound and a finite maximum value, as will generally obtain except in the ideal probability distribution,* the composition time history can be divided into three segments as follows. For such values of t before any breakthrough has developed, that is, for:

$$t \leq \frac{AS}{c}\left(\frac{\bar{f}}{k}\right)_{z=H} \equiv t_b:$$

$$F = 1; \quad R_w(t) = 1; \quad \bar{V} = \frac{Q_o t}{A\int_0^H \bar{f}dz} \qquad [7]$$

At times t between t_b and the time for breakthrough in the tightest lamina, t_m, that is, for:

$$t_b \leq t \leq t_m = \frac{AS}{c}\left(\frac{\bar{f}}{k}\right)_{z=0}:$$

$$R_w(t) = \frac{c\int_0^{z_0} k(z)dz + c\int_{z_0}^H k(z)F(u)dz}{Q_o}: \qquad u = \frac{ct\,k(z)}{A\bar{f}(z)} \qquad [8]$$

where:

$$\frac{k(z_o)}{\bar{f}(z_o)} = \frac{AS}{ct}$$

The cumulative fractional reservoir sweep will be:

$$\bar{Q}_w(t) = \left[ct\int_0^{z_0} k(z)dz + SA\int_{z_0}^H \bar{f}dz + c\int_{z_0}^H k(z)dz \int_{\frac{AS\bar{f}(z)}{ck(z)}}^t F\left(\frac{c\tau k(z)}{A\bar{f}(z)}\right)d\tau\right] \Big/ A\int_0^H \bar{f}dz \qquad [9]$$

Finally, after breakthrough in the tightest layer, that is:

$$t \geq t_m$$

$$R_w(t) = \frac{c\int_0^H k(z)F(u)dz}{Q_o} \qquad [10]$$

The cumulative wet gas recovery and reservoir sweep will be given by the general expressions of Eq 4 and Eq 5.

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* In this case, as will be seen below, the intermediate segment ($t_b \leq t \leq t_m$) comprises the whole composition history.

Eq 7 to 10 provide the basis for treating any type of permeability distribution and the effects of incomplete areal sweep efficiency. They will be illustrated in the following sections by a detailed analysis of the exponential, probability, and linear permeability distributions, including the effects of the areal sweep efficiency for the first of these.

Exponential Permeability Variation

Although there is little statistical evidence that actual condensate reservoir formations have an exponential type of permeability variation, the exponential function is convenient for graphical approximation, and arbitrary distributions can often be resolved into approximate exponential segments. Moreover, with the exponential distribution it is possible to derive closed expressions for the cycling history even when account is taken of the incompleteness of the areal pattern sweep efficiency and the declining wet gas content of the produced gas following the initial dry gas breakthrough.

The exponential permeability variation may be defined by:

$$k(z) = ae^{bz/H} \qquad [11]$$

The constant a evidently represents the minimum permeability ($z = 0$). The maximum permeability is ae^b. As the absolute permeability is of no importance with respect to the effects of stratification, the parameter defining the exponential distribution for the present purposes may be conveniently chosen as the ratio, $r = e^b$, of the maximum to minimum permeability. This "stratification constant" will hereafter be used as an index of the exponential distribution.

As indicated previously, the displacement porosity $\bar{f}$ will be taken as constant.*

The function F will, of course, depend on the well pattern and the areal characteristics of the reservoir. It will have no universal form, although it will be subject to Eq 6. Since a specific form must be chosen in order to apply the general equations of the last section, it will be assumed that:

$$F(u) = 1: \quad u \leq S: \quad F(u) = e^{\frac{S-u}{1-S}}: \quad u \geq S \qquad [12]$$

This form satisfies Eq 6, and roughly approximates the calculated variation of F in special cases. While not quantitatively accurate in general, it should provide a fair approximation of the effects due to the failure of the well pattern to give 100 pct sweep efficiency.

Introducing now the notation:

$$\bar{t} = t/t_b: \quad r = \frac{t_m}{t_b}: \quad b = \log r \qquad [13]*$$

where, by Eq 8, $t_b = \dfrac{AS\bar{f}}{acr}$, it is found by applying Eq 7 that for:

$$\bar{t} \leq 1:$$

$$R_w(\bar{t}) = 1; \quad \bar{V}(\bar{t}) = \frac{S(r-1)\bar{t}}{rb} = \bar{Q}(\bar{t}) \qquad [14]$$

$$1 \leq \bar{t} \leq r:$$

$$R_w(\bar{t}) = \frac{1}{r-1}\left[\frac{r}{S\bar{t}} - 1 - \frac{(1-S)r}{S\bar{t}} e^{\frac{S}{1-S}(1-\bar{t})}\right] \qquad [15]$$

$$\bar{V}(\bar{t}) = \frac{1}{b}\log\bar{t} + \frac{S}{b}(1-\bar{t}/r) - \frac{(1-S)}{b}e^{\frac{S}{1-S}}\left[Ei\left(\frac{-S\bar{t}}{1-S}\right) - Ei\left(\frac{-S}{1-S}\right)\right] \qquad [16]$$

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* The assumed constancy of $\bar{f}$, for the specific permeability distributions treated in detail, further tends to give maximal values for the stratification effects. Aside from the possibility of general trends of decreasing total porosity with decreasing permeability, the $\bar{f}$ should decrease with k because of higher connate water saturations in the low permeability strata. By-passing of the latter therefore should not be as serious from a volumetric standpoint as would be indicated by the calculations based on strictly uniform values of $\bar{f}$.

* The expression for r as the ratio t_m/t_b is, in the light of Eq 7 and 8, evidently equivalent to the previously indicated definition of r as the ratio of the maximum to minimum permeability.

$\bar{t} \geq r$:

$$R_w(\bar{t}) = \frac{r(1 - S)e^{\frac{S}{1-S}}}{S(r - 1)\bar{t}} [e^{-S\bar{t}/(1-S)r} - e^{-S\bar{t}/(1-S)}] \quad [17]$$

$$V(\bar{t}) = 1 - \frac{(1 - S)}{b} e^{\frac{S}{1-S}} \left[Ei\left(\frac{-S\bar{t}}{1 - S}\right) - Ei\left(\frac{-S\bar{t}}{(1 - S)r}\right) \right] \quad [18]$$

In all cases the total throughput at the time $\bar{t}$, as a fraction of the net reservoir pore volume, is:

$$\bar{Q}(\bar{t}) = \frac{S(r - 1)\bar{t}}{rb} \quad [19]$$

It will be readily verified that Eq 14 to 18 are continuous at their mutual contact points. In particular, at the time of breakthrough in the tightest zone, $\bar{t} = r$, Eq 15 and 17 give for $R_w(\bar{t})$:

$$R_w(r) = \frac{1 - S}{S(r - 1)} (1 - e^{\frac{S}{1-S}(1-r)}) \quad [20]$$

which reduces to the coefficient for $r \geq 1$. And for $\bar{V}(r)$, Eq 16 and 18 give:

$$\bar{V}(r) = 1 - \frac{(1 - S)}{b} e^{\frac{S}{1-S}} \left[Ei\left(\frac{-Sr}{1 - S}\right) - Ei\left(\frac{-S}{1 - S}\right) \right] \quad [21]$$

which has the asymptotic value:

$$\bar{V}(r) = 1 - \frac{(1 - S)^2}{Sb} \quad [22]$$

In the limiting case of a uniform formation, $b \to 0$, $r \to 1$, Eq 14 to 19 reduce to:

$$\left.\begin{aligned}
&\bar{t} \leq 1: \\
&R_w(\bar{t}) = 1: \quad \bar{V}(\bar{t}) = (S\bar{t}) = \bar{Q}(\bar{t}) \\
&\bar{t} \geq 1: \\
&R_w(\bar{t}) = e^{\frac{S}{1-S}(1-\bar{t})} = F(S\bar{t}); \\
&V(\bar{t}) = 1 - (1 - S)e^{\frac{S}{1-S}(1-\bar{t})} \\
&\qquad = 1 - (1 - S)F(S\bar{t}); \\
&\bar{Q}(\bar{t}) = S\bar{t}, \text{ for all } \bar{t}
\end{aligned}\right\} \quad [23]$$

In the limit of 100 pct areal sweep efficiency, $S = 1$, Eq 14 to 19 reduce to:

$$\left.\begin{aligned}
&\bar{t} \leq 1: \\
&R_w(\bar{t}) = 1; \quad \bar{V}(\bar{t}) = \frac{(r - 1)\bar{t}}{rb} = \bar{Q}(\bar{t}) \\
&1 \leq \bar{t} \leq r: \\
&R_w(\bar{t}) = \frac{1}{r - 1}\left(\frac{r}{\bar{t}} - 1\right) \\
&\bar{V}(\bar{t}) = \frac{1}{b}\left[1 - \frac{\bar{t}}{r} + \log \bar{t}\right]; \\
&\bar{t} \geq r: \\
&R_w(\bar{t}) = 0; \quad V(\bar{t}) = 1; \\
&\bar{Q}(\bar{t}) = \frac{(r - 1)\bar{t}}{rb}, \text{ for all } \bar{t}
\end{aligned}\right\} \quad [24]$$

For the intermediate time interval, $\bar{Q}$ and $\bar{V}$ can be expressed directly as functions of R_w as:

$$\left.\begin{aligned}
&\bar{Q} = \frac{r - 1}{b[1 + (r - 1)R_w]}, \\
&\bar{V} = 1 - \frac{1}{b}\left[\log\{1 + (r - 1)R_w\} - \frac{(r - 1)R_w}{1 + (r - 1)R_w}\right].
\end{aligned}\right\} \quad [25]$$

To illustrate these general relationships, the wet gas content and cumulative wet gas recovery have been plotted in Fig 1 versus the total gas throughflow for $S =$ 0.60, 0.75, 0.90, and for $r = 1$, 10, and 100. $r = 10$ corresponds to a ratio of the maximum to minimum permeability equal to 10, and this ratio is 100 for $r = 100$. $r = 1$ represents the strictly uniform reservoir. The abscissa values $\bar{Q}$ represent the total gas injection, or production, divided by the total hydrocarbon pore volume. $\bar{Q}$ is related to the argument $\bar{t}$ of Eqs 14 to 18 by Eq 19. The crosses denote the states of first dry gas breakthrough in the most permeable zone, and the circles indicate breakthrough in the tightest layer. The curves for $r = 1$ simply reflect the functional form assumed for F, as required by Eq 23.

It will be noted from Fig 1 that whereas in a uniform formation the dry gas breakthrough will develop after a total through-

flow equal to the sweep efficiency S, dry gas will first appear in the producing wells for $r = 10$ after a throughflow of only 23.4, 29.3, and 35.2 pct of the total hydrocarbon pore volume, for $S = 0.60$, 0.75, and 0.90, respectively. These throughflows also represent the fractions of total displaceable reservoir wet gas content produced by the time of first dry gas breakthrough. And for $r = 100$, the corresponding breakthrough periods will represent recoveries of 12.9, 16.1, and 19.4 pct of the original wet gas content.

For dry gas breakthrough in the tightest layers, with $r = 10$, the total gas processed will correspond to 2.34, 2.93, and 3.52 times the reservoir hydrocarbon pore volume,* for $S = 0.60$, 0.75, and 0.90. By that time the wet gas content of the produced gas will be 7.41, 3.70, and 1.23 pct, respectively. And the total wet gas recovery will be 92.2, 97.2, and 99.56 pct the initial reservoir content. For $r = 100$, the volumes of gas processed before breakthrough in the tightest layer will be 12.90, 16.12, and 19.35 times the reservoir hydrocarbon pore volume, for $S = 0.60$, 0.75, and 0.90. The produced gas will then have wet gas contents equal to 0.68, 0.33, and 0.11 pct, respectively. And the total wet gas recoveries will be 96.1, 98.6, and 99.99 pct of the initial wet gas content of the reservoir.

As shown in Fig 1, the total gas processed and wet gas recovery by the time of first dry gas breakthrough are directly proportional to the sweep efficiency. And the cumulative wet gas recovery curves remain somewhat higher for all values of $\bar{Q}$ after breakthrough for the higher values of S. The wet gas content curves, however, first tend to merge and ultimately cross, al-

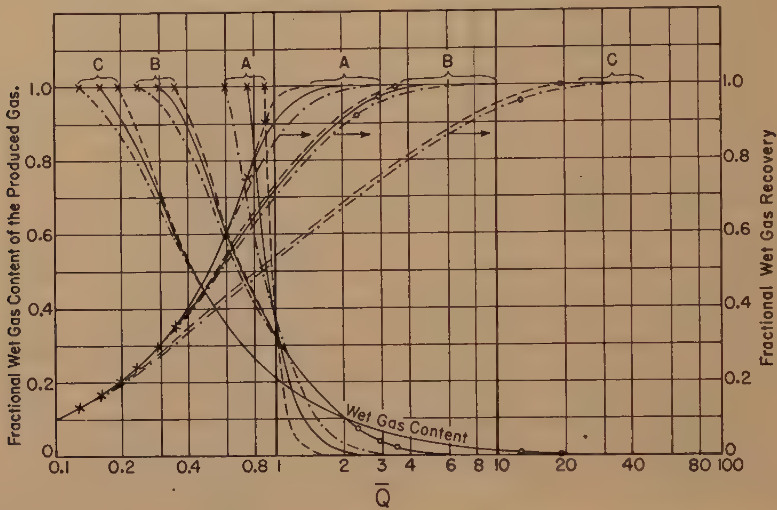

FIG 1—THE CALCULATED VARIATIONS OF THE FRACTIONAL WET GAS CONTENT OF THE PRODUCED GAS AND OF THE TOTAL FRACTIONAL WET GAS RECOVERY VERSUS THE TOTAL GAS PROCESSED IN CYCLING OPERATIONS, IN FORMATIONS WITH EXPONENTIAL PERMEABILITY DISTRIBUTIONS.

$\bar{Q}$ = total gas processed in units of the initial displaceable hydrocarbon pore volume. S = areal sweep efficiency; r = ratio of maximum to minimum permeability, = 1, 10, and 100 for curves A, B, and C. ———: $S = 0.90$; ———: $S = 0.75$; —·—·: $S = 0.60$. Crosses denote states of first dry gas breakthrough; circles represent states of breakthrough in the tightest strata.

* The reservoir hydrocarbon volume used as a unit for expressing the abscissa variable in Fig 1 and in these comparisons is gas volume under reservoir conditions equal to the absolute displaceable net pore volume, and not the volume of the reservoir gas in surface measure. The recoveries are also expressed as fractions of the reservoir content displaceable by cycling. The latter, however, will be equivalent to the actual hydrocarbon content if $\bar{f}$ is taken as the net hydrocarbon porosity.

though the latter divergence is so slight for $r = 10$, and 100 that it could not be shown on the scale of Fig 1. For $r = 1$ the crossing point lies at $\bar{Q} = 1$, by virtue of the functional form assumed for $F(u)$.

effects of stratification may be far more serious in limiting the total condensate recoveries than the areal sweep efficiency. Thus for $r = 100$, which does not represent an abnormally high degree of stratification

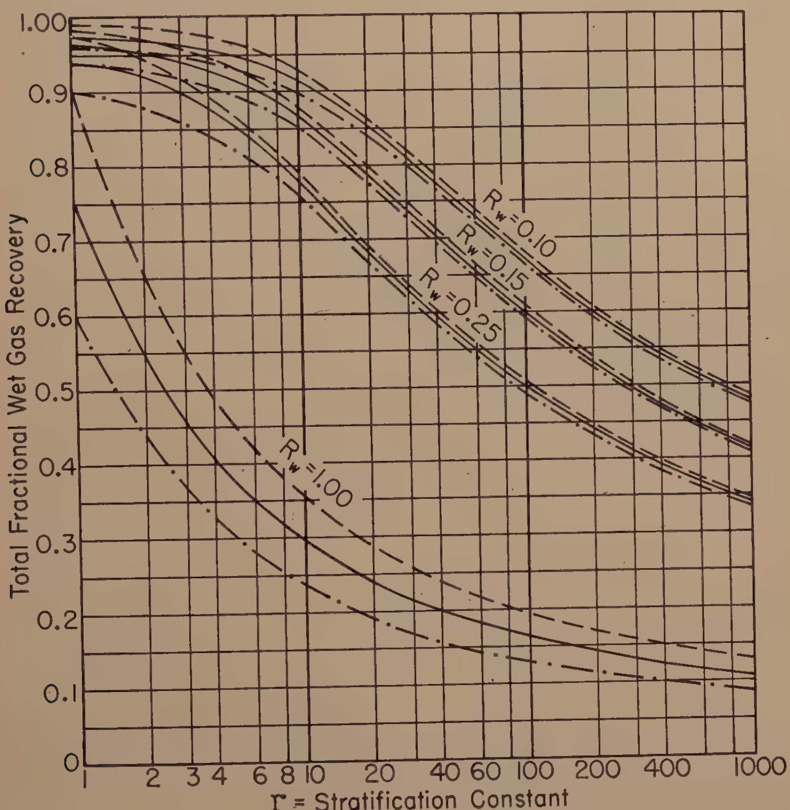

FIG 2—THE CALCULATED VARIATIONS OF THE TOTAL FRACTIONAL WET GAS RECOVERY VERSUS THE STRATIFICATION CONSTANT, r, IN CYCLING OPERATIONS IN FORMATIONS WITH EXPONENTIAL PERMEABILITY DISTRIBUTIONS.

r = ratio of maximum to minimum permeability. R_w = fractional wet gas content of the produced gas at abandonment of cycling. — — —: $S = 0.90$; ———: $S = 0.75$; —·—·: $S = 0.60$; S = areal sweep efficiency.

The variation of the total wet gas recovery versus r by the time the wet gas content falls to fixed limits, at which further injection may become unprofitable, is plotted in Fig 2. As is to be expected, the recovery curves decrease continually with increasing values of r or degree of stratification. For high values of r the recovery assumes an approximately logarithmic decline with increasing r. Fig 2 shows that the as compared to those often observed, the total recovery at an abandonment limit of 15 pct wet gas content will be only 61 pct even if the areal sweep efficiency is 90 pct. The curves for $S = 1$ are not plotted in Fig 2 because they would overlap completely those for $S = 0.90$ for $r > 10$, and would be interlaced with the other curves plotted for lower values of r.

The curves in Fig 2 for $R_w = 1$ represent

the fractional recoveries at the time of first dry gas breakthrough. They are given by:

$$\bar{V}(R_w = 1) = \frac{S(r - 1)}{r \log r} \qquad [26]$$

efficiency, S. It is evidently because of the continued cycling operation to rather low wet gas contents after the initial dry gas breakthrough that the total wet gas recoveries in practice will represent signifi-

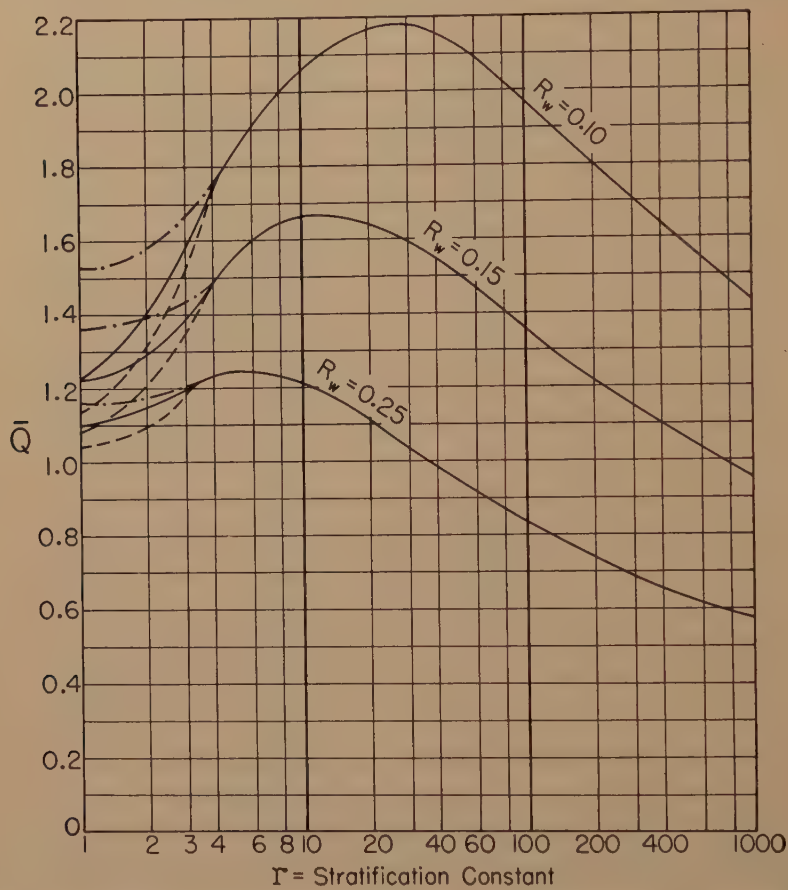

FIG 3—THE CALCULATED VARIATION OF THE TOTAL GAS THROUGHFLOW, $\bar{Q}$, IN UNITS OF THE INITIAL DISPLACEABLE HYDROCARBON PORE VOLUME, VERSUS THE STRATIFICATION CONSTANT, r, IN CYCLING OPERATIONS IN FORMATIONS WITH EXPONENTIAL PERMEABILITY DISTRIBUTIONS.

r = ratio of maximum to minimum permeability. R_w = fractional wet gas content of the produced gas at abandonment of cycling. ———: S = 0.90; ———: S = 0.75; —·—·: S = 0.60; S = areal sweep efficiency.

and may be considered as the composite sweep efficiency resulting both from the well pattern and permeability stratification. It will be seen that even for r = 100 the permeability stratification will reduce the composite sweep efficiency almost by a factor of 5 compared to the areal sweep

cant fractions of the original reservoir contents, as indicated by the upper curves of Fig 2. As implied by Eq 26, the recovery to the time of initial breakthrough is directly proportional to S, in contrast to the much slower variation with S at low values of R_w.

The total volumes of gas throughflow or processed, in reservoir measure, and as fractions of the total reservoir hydrocarbon volume, are plotted versus r in Fig 3, for various abandonment limits for the wet gas content.* It will be observed that these are affected by the areal sweep efficiency only at the lower values of r. In fact $r > 5$, the total throughflow to abandonment is, for practical purposes, independent of S. Moreover, the curves all show maxima in the range of r of 5–30, and then decline as r is still further increased. The initial rise in the curves of Fig 3 is due to the increasing throughflow required to give the approximately constant total wet gas displacements indicated by Fig 2 as the formation becomes increasingly nonuniform. The ultimate declines reflect the corresponding reductions in total wet gas recovery, shown in Fig 2 at high stratification ratios, which can be swept out by relatively small volumes of injected gas. It will be noted also that the volumes of gas processed will vary more rapidly with the abandonment limit of wet gas content than the total wet gas recovery.

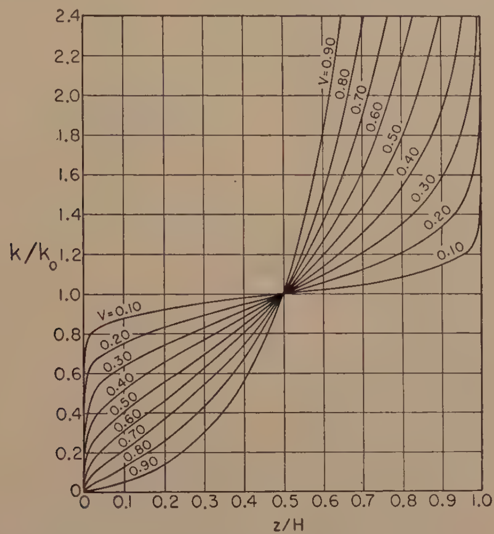

FIG 4—CARTESIAN PLOTS OF THE PERMEABILITY, k, VERSUS THE DEPTH, z, IN IDEAL PROBABILITY DISTRIBUTIONS.

k_o = most probable value of k. H = total net thickness of productive section. V = "variation" of the probability distribution.

PROBABILITY DISTRIBUTION

The probability distribution in permeability may be defined by the equation:

$$\frac{dz}{d\Psi} = \frac{H}{\sigma\sqrt{2\pi}} e^{-\Psi^2/2\sigma^2};$$

$$\Psi = \log k/k_o \quad [27]$$

For convenience in subsequent analysis the logarithm to the base e has been used in defining Ψ, rather than $\sqrt{2}$, as introduced in previous work.[4] k_o is the permeability of maximum probability. σ is the standard deviation, and is related to the "variation" V by[3]:

$$\sigma = -\log(1 - V); \qquad V = 1 - e^{-\sigma} \quad [28]$$

H is the total thickness of the productive section. If the probability distribution is strictly satisfied it includes the complete permeability range of 0 to ∞. While this is

* The total gas throughflows for $R_w = 1.00$ are evidently equal to the total wet gas recoveries for $R_w = 1.00$ plotted in Fig 2.

not to be expected from both physical and practical standpoints, the actual volumetric and flow capacity contributions of the regions of very low and very high permeabilities will be extremely small because of the inherent characteristics of the probability distribution. A Cartesian coordinate plot of the permeability distribution for various values of V, as implied by Eq 27, is given in Fig 4.

It may then be shown that:

$$
\left.
\begin{aligned}
R_w(t) &= \frac{1}{2}\left[1 + I\left(\frac{\bar{\Psi}}{\sqrt{2}\,\sigma} - \frac{\sigma}{\sqrt{2}}\right)\right]: \quad \bar{\Psi} > \sigma^2 \\
&= \frac{1}{2}\left[1 - I\left(\frac{\sigma}{\sqrt{2}} - \frac{\bar{\Psi}}{\sqrt{2}\,\sigma}\right)\right]: \quad \bar{\Psi} < \sigma^2
\end{aligned}
\right\} \quad [31]
$$

where I is the probability integral.

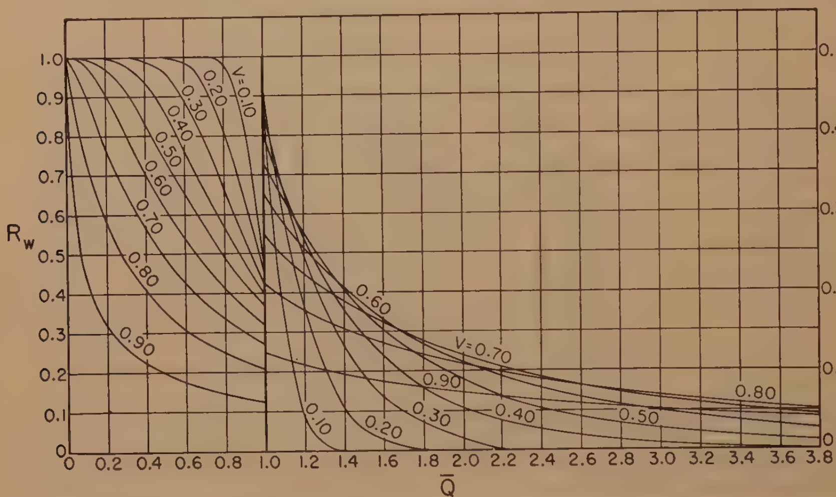

FIG 5—THE CALCULATED COMPOSITION HISTORIES FOR CYCLING SYSTEMS WITH PROBABILITY DISTRIBUTIONS IN PERMEABILITY.

R_w = fractional wet gas content of the produced gas. $\bar{Q}$ = total gas throughflow in units of the initial displaceable hydrocarbon pore volume. V = "variation" of the probability distribution. For $\bar{Q} > 1$, R_w scale is that on right. Areal sweep efficiency assumed = 1.00.

The total flow capacity of the section with the permeability distribution of Eq 27 will be:

$$Q_o = cHk_oe^{\sigma^2/4} \quad [29]$$

where c is essentially the same constant as introduced in Eq 2. To determine the composition history of the produced gas, it is noted that at time t there will develop breakthrough* in all strata for which Ψ exceeds $\bar{\Psi}$, given by:

$$\bar{\Psi} = \log \frac{A\bar{f}}{ck_ot} \quad [30]$$

The cumulative fractional wet gas recovery, as a function of t or $\bar{\Psi}$ is given by:

$$
\left.
\begin{aligned}
\bar{V}(t) &= \bar{Q}R_w(t) + \frac{1}{2}\left[1 - I\left(\frac{\bar{\Psi}}{\sqrt{2}\,\sigma}\right)\right]: \quad \bar{\Psi} > 0 \\
&= \bar{Q}R_w(t) + \frac{1}{2}\left[1 + I\left(\frac{-\bar{\Psi}}{\sqrt{2}\,\sigma}\right)\right]: \quad \bar{\Psi} < 0
\end{aligned}
\right\} \quad [32]
$$

where $\bar{Q}$ is again the cumulative throughput, expressed in units of the total net displaceable pore volume, and is related to $\bar{\Psi}$ by:

$$\bar{Q}(t) = e^{-\bar{\Psi}+\sigma^2/4} \quad [33]$$

* It is assumed throughout this treatment of the probability distribution that the areal sweep efficiency, S, is 100 pct.

Thus, on choosing σ or V, through Eq 28, $\bar{\Psi}$ can be computed as a function of $\bar{Q}$ from Eq 33. Eqs 31 and 32 will then give R_w and $\bar{V}$ as functions of $\bar{Q}$.

complete R_w curves must all be equal to unity, they ultimately cross in Fig 5, as they do in Fig 1, at higher values of $\bar{Q}$. To minimize the complex overlapping in the region

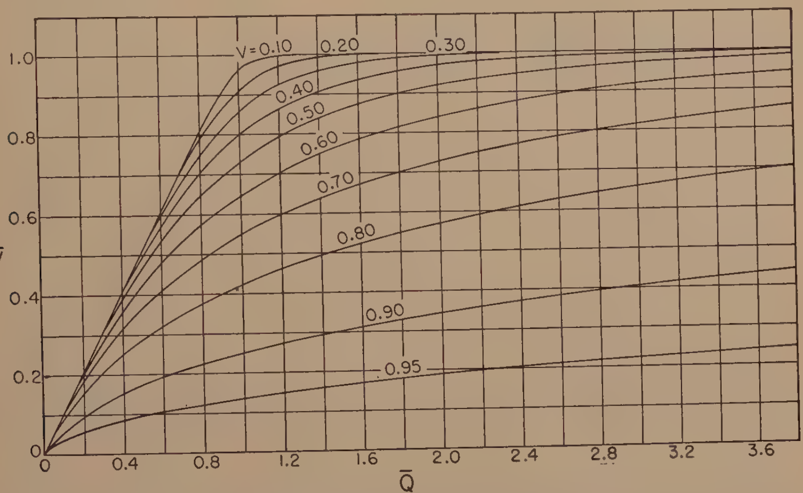

FIG 6—THE CALCULATED CUMULATIVE WET GAS RECOVERY HISTORIES FOR CYCLING SYSTEMS WITH PROBABILITY DISTRIBUTIONS IN PERMEABILITY.

$\bar{V}$ = cumulative wet gas recovery in units of the initial total displaceable wet gas reservoir content. $\bar{Q}$ = total gas throughflow in units of the initial displaceable hydrocarbon pore volume. V = "variation" of the probability distribution.

of crossing, the R_w scale in Fig 5 has been expanded by a factor of 2 for $\bar{Q} > 1$.

The composition histories so calculated for fixed values of the variation, V, are plotted in Fig 5. Although a Cartesian scale is used here for the total fractional throughflow, $\bar{Q}$, it will be seen that qualitatively the curves are of the same character as those plotted in Fig 1 for an exponential permeability variation. As is to be expected, the period of undiluted* wet gas production increases as V decreases, that is, as the formation becomes more uniform. Moreover, after breakthrough the decline in wet gas content falls more sharply as V decreases. Finally, since the areas under the

The cumulative wet gas recovery for fixed variation parameters, V, is plotted versus the total gas throughflow in Fig 6. These curves, similar to those of Fig 1 for the exponential permeability distribution, show the increasingly rapid completion of the displacement of the wet gas as the variation decreases, that is, as the formation becomes more uniform. Thus with a variation of only 0.10, 96 pct of the wet gas content of the reservoir would be displaced after a throughflow of only 1 reservoir net displaceable pore volume, for 100 pct areal sweep efficiency. On the other hand, if the variation were 0.95, only 22 pct of the displaceable reservoir wet gas content would be displaced even after a throughflow of 3 reservoir pore volumes.

Analogous to Fig 2, the cumulative wet gas recovery to limiting values of wet gas

* Strictly speaking there will necessarily be an immediate dry gas breakthrough for all values of V in a strict and complete probability distribution system. However, as is clear from Fig 5, there is always an initial segment for which $R_w = 1$ from a practical standpoint. Moreover, the R_w versus $\bar{Q}$ curves always begin with zero slope at $\bar{Q} = 0$, although this could not be shown for the higher values of V.

content in the produced gas, R_w, is plotted versus the variation V in Fig 7. It will be seen that for variations less than 0.5 more than 80 pct of the displaceable wet gas content of the reservoir will be recovered during the cycling operations even if the latter be abandoned at a wet gas content of the produced gas of 25 pct. These recoveries would be reduced somewhat in actual systems where the areal sweep efficiencies are less than 100 pct. At high variations, however, the areal sweep efficiency will be of smaller importance, as may be inferred from Fig 2.

The total gas throughflow, as a function of the variation, for fixed limiting values of R_w, is plotted in Fig 8. These curves show maxima similar to those of Fig 3 for the exponential permeability distribution, and for the same reasons. Moreover, the values of these maxima are only slightly greater than those of Fig 3.

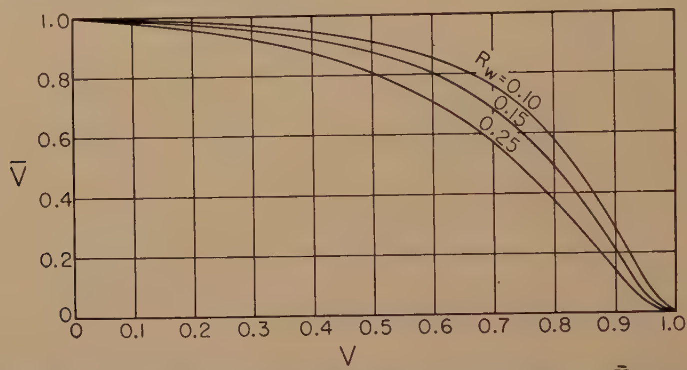

FIG 7—THE CALCULATED CUMULATIVE WET GAS CYCLING RECOVERIES, $\bar{V}$, IN UNITS OF THE INITIAL TOTAL DISPLACEABLE WET GAS RESERVOIR CONTENT, FROM FORMATIONS WITH PROBABILITY DISTRIBUTIONS IN PERMEABILITY VERSUS THE "VARIATION," V, OF THE DISTRIBUTION.
R_w = fractional wet gas content of the produced gas at abandonment of cycling.

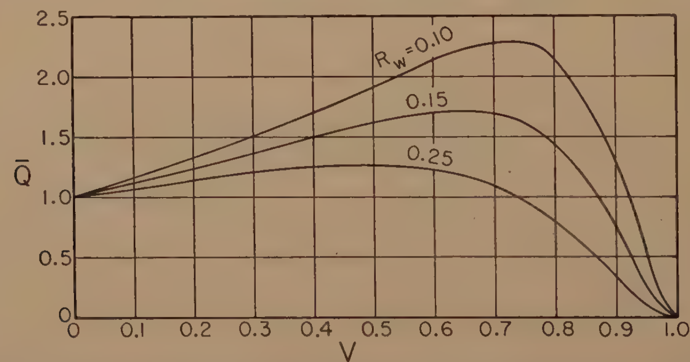

FIG 8—THE CALCULATED TOTAL GAS THROUGHFLOW, $\bar{Q}$, IN UNITS OF THE INITIAL DISPLACEABLE HYDROCARBON PORE VOLUME, IN CYCLING OPERATIONS WITH PROBABILITY DISTRIBUTIONS IN PERMEABILITY VERSUS THE "VARIATION," V, OF THE DISTRIBUTION.
R_w = fractional wet gas content of the produced gas at abandonment of cycling.

LINEAR PERMEABILITY VARIATION

As a final type of a continuous permeability distribution, the results to be expected for a linear variation will be briefly outlined. This, too, can be defined, by analogy with the exponential distribution,

by a parameter r, representing the ratio of the maximum to minimum permeability, that is, by:

$$k(z) = k_o[1 + (r - 1)z/H] \qquad [34]$$

where k_o is the minimum permeability, at $z = 0$.

Although closed expressions can also be obtained for this case for the composition history with imperfect areal sweep patterns ($S < 1$), using an F function of the type of Eq 12, the study of the exponential case indicates that the exact value of S is of minor importance as long as it is of the order of 0.70 or greater. Assuming then for simplicity that $S = 1$, it is readily found, by the methods used for the exponential and probability distributions, that the composition histories can be explicitly expressed by the equations:

$$\left.\begin{aligned}
&\bar{Q} \leq \frac{1+r}{2r}: \\
&R_w = 1; \qquad \bar{V} = \bar{Q}; \\
&\frac{1+r}{2r} \leq \bar{Q} \leq \frac{1+r}{2}: \\
&R_w = \frac{1}{r^2 - 1}\left[\frac{(r+1)^2}{4\bar{Q}^2} - 1\right]; \\
&\bar{V} = \frac{r}{r-1} + \bar{Q}R_w - \frac{(1+r)}{2(r-1)\bar{Q}}; \\
&\bar{Q} \geq \frac{1+r}{2}: \\
&R_w = 0: \qquad \bar{V} = 1
\end{aligned}\right\} \qquad [35]$$

The total recovery and throughflow curves versus the stratification parameter, for fixed values of the limiting fractional wet gas content of the produced gas, as calculated by Eq 35, are plotted in Fig 9 and 10. Comparing Fig 9 with Fig 2, it will be seen that especially for the higher values of the stratification constant the total recoveries fall off much slower for the linear than for the exponential permeability distribution. In fact, whereas in the latter $\bar{V}$ asymptotically approaches 0 with increasing r, $\bar{V}$ approaches $1 - \sqrt{R_w}/2$ in the limit of indefinitely increasing r for the linear distribution. That is, there will be a definite nonvanishing wet gas recovery, to pre-assigned abandonment limits of R_w, regardless of the degree of stratification, as long as the permeability distribution is linear. The total throughflows, as plotted in Fig 10, also approach nonvanishing limits—$\frac{1}{2\sqrt{R_w}}$—with increasing r for a linear permeability distribution, although the curves of $\bar{Q}$ versus r show maxima similar to those of Fig 3. This is, of course, associated with the nonvanishing total recoveries implied by Fig 9.

The reason for the differences between the behavior of linear and exponential distribution systems, with the same ratios of extreme permeabilities, evidently lies in the nature of the permeability variations between the limits. Thus whereas in the linear distribution the mean (integrated) permeability will always lie at the midpoint of the thickness, it moves toward greater depths as r increases for an exponential distribution. The fraction of the section having a permeability exceeding the mean decreases as $\frac{1}{b}\log b$ as b and r increase. In the latter case the high permeability "half" of the pay becomes an infinitesimal part of the section volumetrically, while it still contributes half of the flow capacity.

Conclusions

As would have been expected from elementary considerations, the gross composite efficiency of cycling operations continually decreases as the degree of stratification or variation in permeability increases. The effect of such stratification may be far more serious in limiting the total recoveries and operating life of cycling operations than the areal or pattern efficiency, except in quite uniform formations.

If the permeability distribution is exponential, the stratification may be defined by the ratio of the maximum to minimum permeability. The wet gas recoveries to

initial dry gas breakthrough decrease rapidly with increasing values of this ratio, being only 35 pct, at a value of 10 even if the areal sweep efficiency is 90 pct. At a permeability ratio of 1000 the initial breakthrough recovery for a 90 pct areal sweep efficiency will be only 13 pct. However, if the cycling operations are continued to low values of wet gas content in the produced gas, the total recoveries are very materially increased. At an abandonment limit of 10 pct wet gas, the total recoveries may exceed 90 pct of the initial reservoir content if the stratification ratio is 10; and even when the latter is 1000, the recoveries will be of the order of 50 pct in an exponential permeability distribution.

The total gas throughflow to various abandonment limits first increases as the stratification ratio increases, reaches a maximum, and finally decreases again. The maximum values are rather moderate, and equals only 2.18 times the hydrocarbon pore volume even if the cycling is abandoned at a limit of only 10 pct wet gas content.

In ideal probability distributions of permeability the degree of uniformity may be expressed by the value of the "variation," which increases from 0 to 1 from a

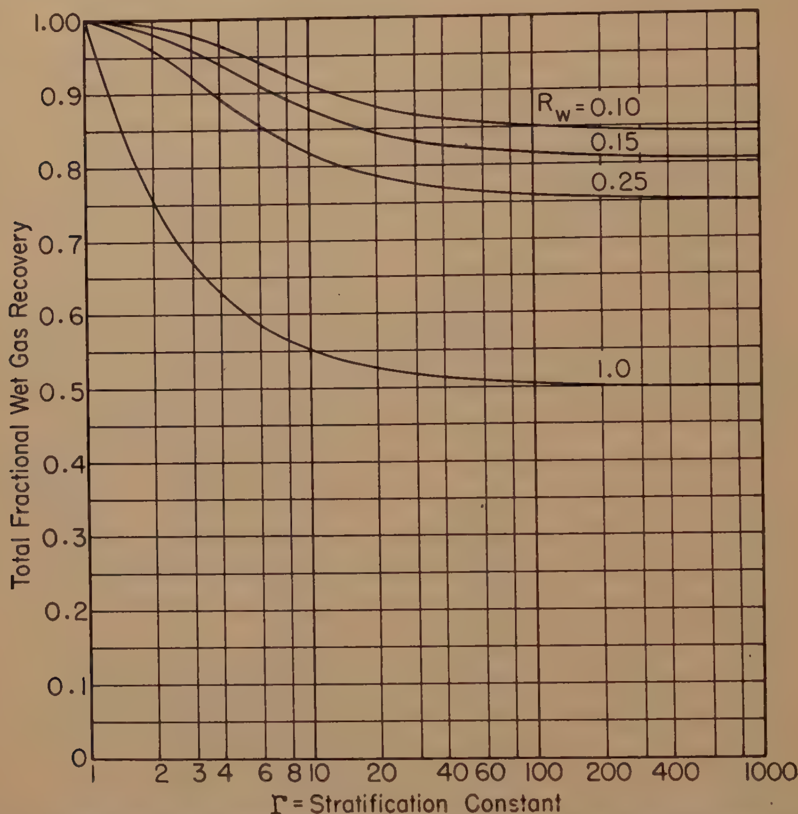

FIG 9—THE CALCULATED VARIATION OF THE TOTAL FRACTIONAL WET GAS RECOVERY IN CYCLING OPERATIONS IN LINEARLY STRATIFIED FORMATIONS VERSUS THE STRATIFICATION CONSTANT, r = RATIO OF MAXIMUM TO MINIMUM PERMEABILITY.

R_w = fractional wet gas content of the produced gas at abandonment of cycling.

strictly uniform section to one of maximum variability. In this distribution the permeability theoretically would vary from 0 to ∞, but the extreme limits represent in-donment, if the "variation" is less than 0.70. The corresponding total gas throughflows versus the variation show maxima as in the case of the exponential distribution,

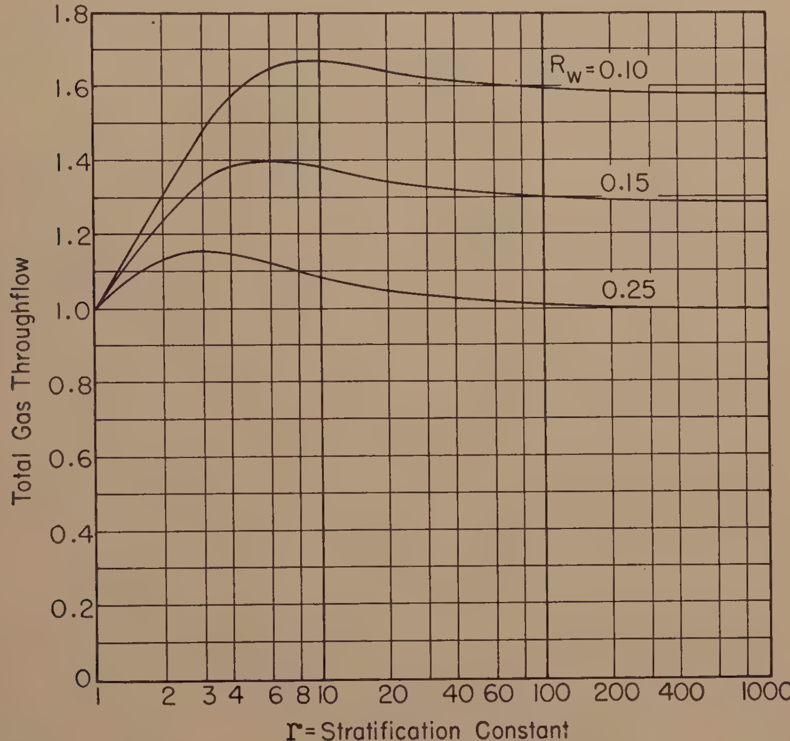

FIG 10—THE CALCULATED VARIATION OF THE TOTAL GAS THROUGHFLOW, IN UNITS OF THE INITIAL DISPLACEABLE HYDROCARBON PORE VOLUME, IN CYCLING OPERATIONS IN LINEARLY STRATIFIED FORMATIONS VERSUS THE STRATIFICATION CONSTANT, r = RATIO OF MAXIMUM TO MINIMUM PERMEABILITY.

R_w = fractional wet gas content of the produced gas at abandonment of cycling.

finitesimal volumetric contributions. Thus while theoretically there would be some dry gas breakthrough immediately for all values of the variation, the dry gas dilution will be so slow, especially for low values of the variation, that the formations will simulate those with finite upper limits in permeability. The total wet gas recoveries decrease monotonically with increasing values of the variation, but will exceed 75 pct, for 100 pct areal sweep efficiency and 10 pct limiting wet gas content for abandonment and the values of the maxima are only slightly higher than in the latter.

The linear permeability distribution can also be defined by the ratio of maximum to minimum permeability. The general trends of the curves of total wet gas recovery and throughflow with the stratification ratio are similar to those for the exponential distribution. In contrast to the latter, however, nonvanishing asymptotic limits of total recovery and throughflow are approached as the stratification ratio is in-

definitely increased in the case of the linear distribution. In particular, such limits are 84.2 pct for total recovery at an abandonment wet gas content of 10 pct, and 75 pct even if the cycling is abandoned at a wet gas content of 25 pct. Moreover, the initial dry gas breakthrough will never develop until at least 50 pct of the reservoir volume is swept out.

Acknowledgment

The writer is indebted to Miss M. O. Taylor for carrying through the calculations on which the figures of this paper are based, and to Dr. P. D. Foote, Executive Vice-President of Gulf Research and Development Company, for permission to publish this paper.

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CHAPTER V. *Production Engineering*

Experimental Production Projects and Exploratory Drilling at Elk Hills

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(Los Angeles Meeting, October 1947)

ABSTRACT

THE termination of the recent war marked a major change in the oil-field operations at Elk Hills. Production was greatly curtailed, various experimental production projects were started, and a long-range exploratory program was inaugurated. Production was reduced from the wartime peak of 65,000 bbl per day to the current rate of about 8000 bbl per day in order to maintain an available source of crude that can be drawn upon during a national emergency. The existing production rate is deemed essential to carry on the experimental production projects. These projects are being conducted to determine the best methods and means of maintaining the Reserve, shut in, but in a state of readiness to produce the maximum quantity of oil in the most expeditious manner. Projects now being investigated include: (1) protection of surface equipment; (2) repair of wells that might damage the reservoir; (3) gas injection; (4) water encroachment, (5) gravity drainage.

An exploratory program is being carried on to determine the amount of recoverable oil in the unexplored portions of the Reserve. The Shallow-zone exploration is practically completed, but owing to the complexity of the Stevens structure and the magnitude of the oil discoveries in the Stevens, exploration will probably continue in that zone for another two years.

INTRODUCTION

Summary of Development History of Elk Hills

Although a detailed history of Elk Hills oil field is presented in various publications,[1,2] a summary of its unusual development and production history will be given in order that the present problems may be more readily understood.

The first development that resulted in commercial production was in the central part of the Reserve. The first well, Hay No. 1, in sec 36-R,* was completed in January 1919, and was soon followed by 47 others in the same general area. It is commonly referred to as the Hay-Carman area and was shut in in stages from 1925 to 1934 as a result of litigation regarding the title to the land. Not being highly productive, only about 6½ million barrels of oil with a large volume of gas was produced from the area prior to the shutdown.

Shortly after the start of the development of the Hay-Carman area, drilling was started 6 miles east in sec 36-S. Tupman No. 1 came in for 5000 bbl per day early in 1920. It was followed by more than 200 others in the next few years, and the field became one of major importance. Produc-

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The opinions or conclusion contained herein are essentially those of the writers and are not to be construed as official or reflecting the views of the Navy Department, The Unit Operation, or the Standard Oil Company of California.

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[1] References are at the end of the paper.

* See page 354 for legend of township and range abbreviations.

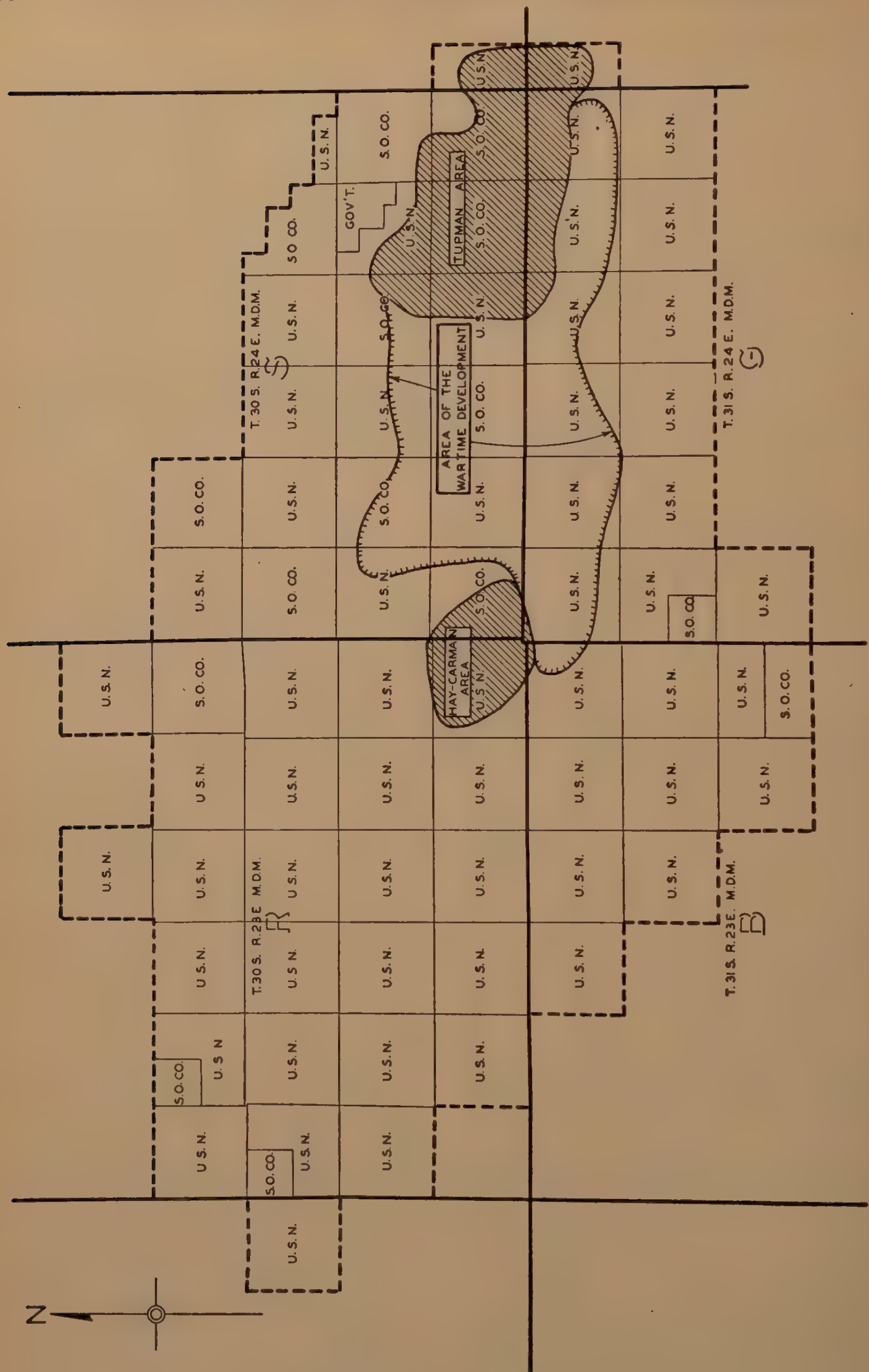

Fig 1—Developed areas, Elk Hills.

tion for the year 1921 was over eighteen million barrels of oil, which amounted to 16 pct of the total for the state that year. This area is generally called the Tupman area. The relationship of the Hay-Carman and Tupman areas is shown on Fig 1.

The area between Hay-Carman and Tupman is checkerboarded with alternating Government and fee-owned sections. In 1912 President Taft set aside an area of 38,069 acres of Government-owned land in the Elk Hills as a Government oil reserve. Since it was to be administered by the Navy Department, it was called Naval Petroleum Reserve No. 1. It was intended to provide a reserve of oil to meet any national emergency. The Tupman development just described was located outside of the eastern boundary of the Reserve. In an effort to prevent drainage from the undeveloped Reserve, the Government then issued strip leases, offsetting the developed area. These leases were given to private oil companies and remained in effect until the present Unit Plan was formed. Whether or not these leases had the desired effect, and prevented drainage, can be argued, but the Government did receive unusually high royalties as a remuneration for these leases. In cooperation with the Government's policy of maintaining a reserve, the fee-owned land within the boundaries of the original Reserve was not developed. An act of Congress of June 30, 1938 required that all existing leases be terminated upon their expiration date and that steps be taken to ensure a more certain reserve of oil. The resulting program ended in the formation of the present Unit Plan. It should be noted that during the 20 years between the eastern discovery and the unitizing of the field, the extreme eastern part of the field was under production while the remainder of the field was either undeveloped or shut in.

With the termination of the active leases on Government land, there remained only one operator in the area, The Standard Oil Company of California. In order to unitize or otherwise consolidate the Reserve, more information was required as to the structure and nature of sands underlying the area. Consequently, 13 exploratory wells were drilled in the area by this company during 1941. The fact that the entire Elk Hills structure was not included within the boundaries of the original Reserve was recognized and in October 1942, by Executive Order, President Roosevelt extended the limits of the Reserve to include all the then-known productive areas.

In order that the field might be operated according to the dictates of good engineering practice, without competition between owners, and at the same time reserve the maximum amount of oil for the needs of the Government in national emergencies, the Unit Plan Contract between The Standard Oil Company of California and the United States Navy was signed by President Roosevelt in June 1944. All development and production of the field subsequent to that date have been carried on by the operator, The Standard Oil Company of California, under a separate operating agreement.

At the outbreak of World War II the field's production was about 12,000 bbl per day. During the negotiations for the Unit Plan, 21 more wells were drilled and the production was increased to about 15,000 bbl per day by June 1944. To prosecute the war, Congress in June 1944 authorized the development of the Reserve to increase its production to 65,000 bbl per day with a limit on total production of 30 million barrels. The first well under this program was spudded June 29, 1944. By the use of as many as 19 strings of tools, the production was increased to 65,000 bbl by Feb. 28, 1945. To take care of normal decline and to increase the capacity to cover down-time of wells for routine maintenance, drilling was continued until hostilities ended in

August 1945. During this 15 months of development, 317 wells, averaging 2931 ft in depth, were drilled, with an average drilling time of 14 days per well. Only 4 wells of this number had to be abandoned. The field's capacity was set at 71,000 bbl per day with a "good operating rate" of 65,000 bbl per day.

At the termination of hostilities, production was cut back to its former figure of 15,000 bbl per day. During the period from June 1944 to August 1945, the field produced over 15 million barrels of oil, 5½ million Mcf of gas and 2 million gallons of gasoline. Practically all of this production was taken from the Shallow Zone, with only a small amount from the few wells in the Stevens Zone. As shown on Fig 1, the major part of the development took place in the eastern portion of the field between the Tupman and the Hay-Carman areas. In May 1946, production from the field, except for exploratory testing, was reduced to 8400 bbl per day and has since remained at or below that figure. Only a small quantity is produced from the exploratory wells and the total from the field in 1946 averaged about 10,550 bbl per day. This production is considered necessary to carry out the exploratory program and various readiness projects that will be explained later in detail.

This covers in brief the two major periods of development, the first in the twenties by various companies in competition but with many Government restrictions, and the second during the recent war by the Unit Operation.

Unit Operations

Congress in 1944 authorized the Secretary of Navy to act for the United States Government in entering into a contract with the Standard Oil Company of California for the purpose of unitizing and operating the Elk Hills. The present Unit Plan Contract and Operating Agreement were entered into on June 19, 1944, but the basic date for all computations and retroactive features is Nov. 20, 1942. This Unit Plan differs in some respects from the conventional unit operation. It will be described briefly to point out these differences. Both parties contributed all their lands within the boundaries of the Reserve, and the participating percentages were calculated from the weighted acre-feet of productive formations underlying the property of each party. Since a large part of the area was unexplored, the contract made provisions for a revision of these percentages from time to time as new information becomes available. When revisions are so made they are retroactive to Nov. 20, 1942, the date of inception of the contract. An extensive exploratory program is now being carried out to complete this information and it will be described later in detail. Since the area was designated as a Government Reserve, the contract gives control of the property to the Government, represented by the Secretary of the Navy, with certain compensations to the second party for loss of control.

The operations are conducted under the supervision of an Operating Committee composed of two members, one to represent each party to the contract. The Plan also provides for a six-man Engineering Committee to meet periodically and approve such engineering matters as exploratory drilling locations, new participating percentages, or other matters referred to them by either party. The Standard Oil Company of California was selected as operator and under the present Operating Agreement conducts the operations as directed by the Operating Committee. Performance of the work is at actual cost.

Experimental Production Projects

General Purpose and Scope

At the termination of hostilities in World War II, the engineers at Elk Hills were confronted with the problem of how best to

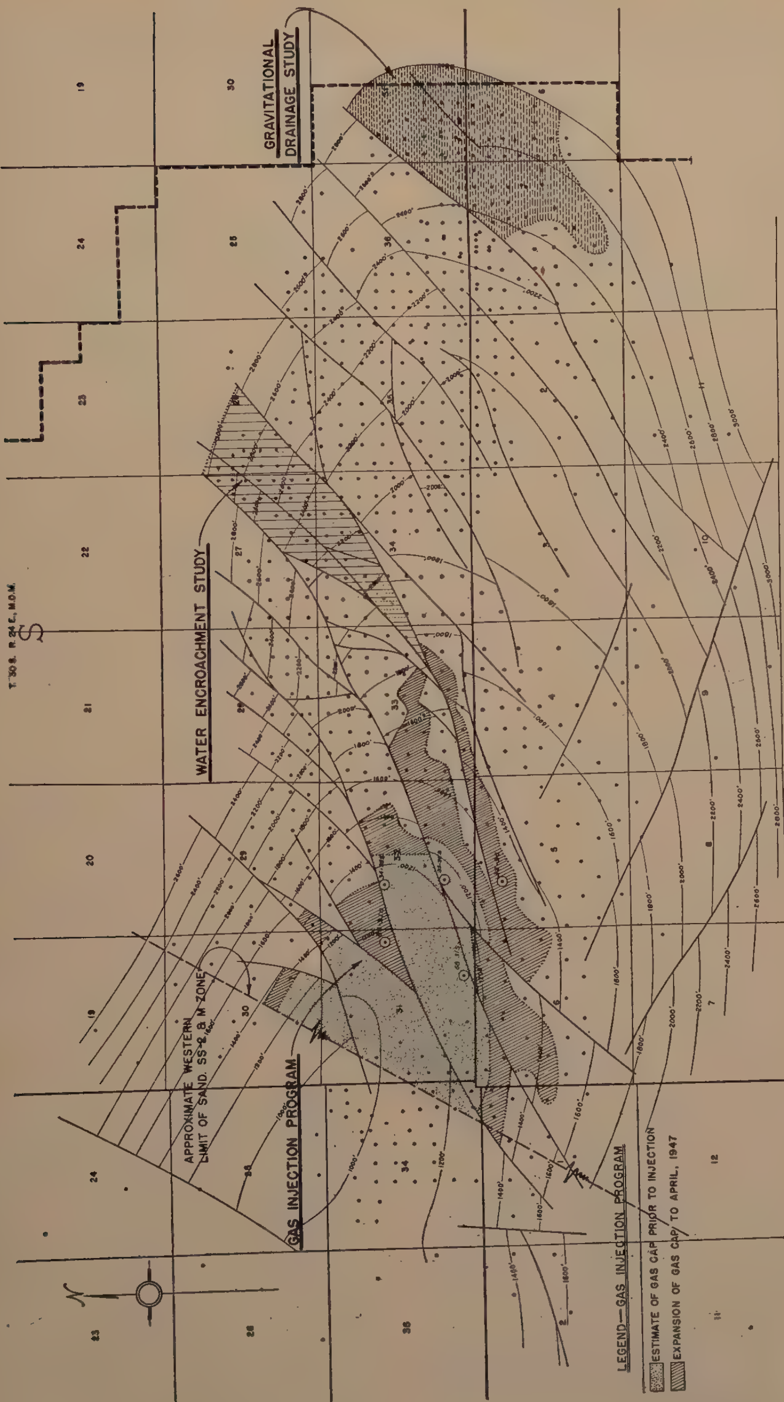

FIG 2—PRODUCTION PROJECTS.

operate and maintain the field in a practically shut-in condition and at the same time keep the field in a state of readiness to produce the maximum quantity of oil upon short notice. Some of the problems to be considered are: (1) the desirability and feasibility of removing, storing or disposing of field equipment and facilities which are not required for immediate use; (2) the development of a program which will create the reservoir conditions calculated to ensure the largest ultimate recovery from the field; (3) the type of pressure maintenance or restoration of pressure program best suited for the Shallow Zone; (4) the development of a program for the periodic testing of the wells, which will help maintain the field in a condition of availability for production and provide a continuing estimate of the productive capacity of the field; (5) the development of a program of immediate and future remedial work to maintain the wells in the best possible condition for the prompt availability of production.

At the start of this project, which is commonly referred to as the "Readiness Program," there was insufficient information upon which to base a sound operating policy. It was decided therefore to conduct experimental production projects in order to gather additional information. The various projects now under investigation are: (1) protection of surface equipment; (2) rotating production test; (3) repair and remedial work; (4) gas injection; (5) water encroachment; (6) gravity drainage. Each of these will be discussed to show what has been accomplished so far.

Structure and Stratigraphic Section

The eastern portion of the field in which all the production studies are being made is the eastern nose of a badly faulted anticline. Fig 2 shows the degree of faulting in this area. The faults are of the normal type dipping 40 to 60° with displacements of 50 to 200 ft. Whether or not all of these faults are fluid barriers is not known, but pressure studies indicate that many of them may be. This half of the field covers 20 sections, or roughly 13,000 acres, and has an oil closure of about 1500 ft. Production is from a series of sand members as shown on the type section in Fig 3. A very good diagnostic fossil marker, the *Scalez Petrolia*, occurs throughout the area and is used for the contour mapping of the Shallow Oil Zone. The principal zones produced in the eastern area occur about 20 ft below this marker and consist of a 150 to 250 ft of zone with some solid sand members 35 to 50 ft thick.

The production from the Tupman area was derived chiefly from the SS-1 with minor amounts from the AS, SS-2 and possibly some from the M. The lower sands are wet in a good part of this area. During the war development program the SS-1 sand was found to thin and pinch out to the west at a location about halfway between the Tupman and the Hay-Carman areas. It was also observed that the SS-2 and M sands unite west of this line and exist as a single sand body. During the recent development program two types of completions were made. SS-1 and 2 completions were alternated with M and SM completions in the area where the SS-1 sand was present. Thus 20-acre, subsurface spacing exists in this area, although the surface location is 10-acre spacing. In the western portion of the new development where the SS-1 sand is not present, the wells were completed in the SS-2-M sand on a 20-acre spacing. A few wells in the extreme western portion of the area were completed in sand lenses in the Bittium and Wilhelm Zones. Further description of this Shallow Zone stratigraphy is given in the second portion of this report.

The physical characteristics of the sands are such as to promote a high rate of production and ultimate recovery. The average permeability is approximately 1½ darcys, the porosity is about 35 pct and the connate water approximates 30 pct, being as low as 5 pct in the most permeable fingers. The

oil ranges from 14 to 30° API depending on the location on structure. The viscosity of the reservoir oil varies considerably with locality but averages about 5.0 centipoises.[3] dry after flushing with a solution of 60 pct ethylene glycol, 35 pct water and 5 pct water-soluble cutting oil. Exposed polished surfaces were covered with rust-preventive oil and all belts were stored in a

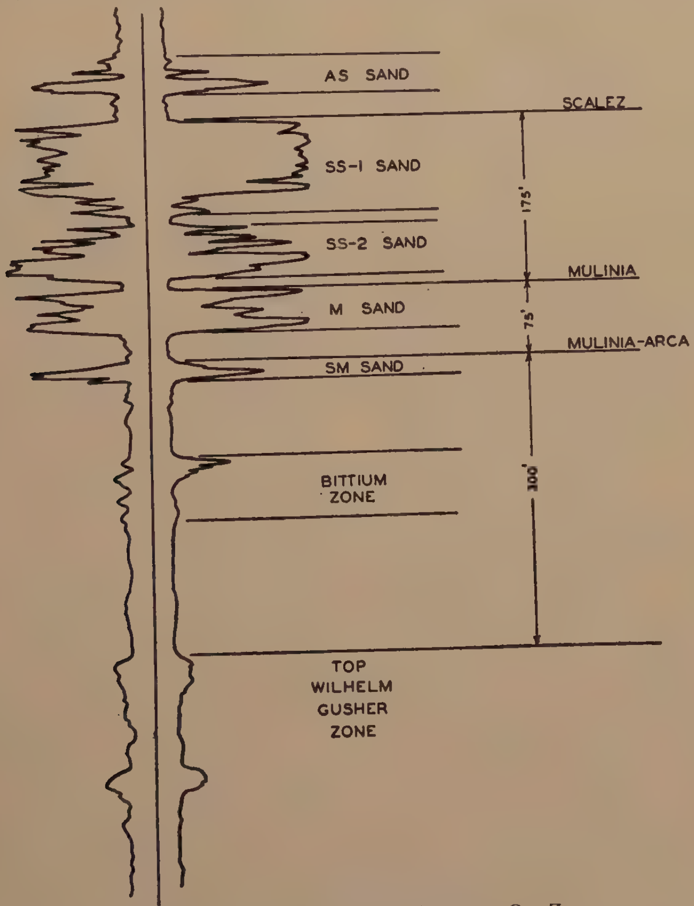

FIG 3—PRODUCTIVE MEMBERS, SHALLOW OIL ZONE.

PROTECTION OF SURFACE EQUIPMENT

A decision to leave all the producing equipment on some 500 wells to be shut in brought up the problem of how best to protect this equipment from corrosion. The rods and tubing were left in the wells and the engines "pickled." The pickling consisted of replacing the normal oils, in the crankcase and reduction gears, with inhibited oil designed to prevent rust formation on a closed engine. Radiators were left cool, dry, dark storehouse. During the annual 10-day production test on these wells the engines are operated on the inhibited oil. This oil requires changing only about every five years when used in this manner. After each test the well equipment is returned to its former pickled condition. Some wells have been in this condition of preservation for over a year and show no signs of deterioration. Whether this process will be effective over a long period of idleness is not known.

Rotating Production Tests

One of the first programs deemed necessary was a test schedule to determine the mechanical condition of each well and its productive characteristics, and to gather data to aid in making estimates of the productive capacity of the field. To accomplish this, a rotating production schedule was set up under which each idle well would be produced once a year. The wells are produced in small groups of 10 or 15 in order to facilitate gauging. The entire field is covered twice a year; that is, certain wells in each section are produced the first time around and the remainder are produced six months later. This gives semiannual information on each area and annual information on individual wells.

The individual test consists of putting the well on production at a minimum operating speed and casing pressure to ensure high fluid levels. When the well production has steadied, which generally takes several days, subsurface operating pressure is determined either by measuring the fluid level or by means of the depth pressure recorder. The use of offset tubing heads permits the running of the pressure bomb in the annulus while the well is on production. As soon as the subsurface operating data look consistent the well is shut in. When the well reaches static equilibrium the subsurface pressure is again taken. To complete the average test requires about 10 days production.

From these data the productivity index of individual wells is computed and the changes in productivity of individual wells, certain areas, or the field as a whole can be estimated. The data also give valuable information on the pressure changes or water entries in various areas as the field reorients itself in reaching an equilibrium shut-in condition after the high producing rate maintained during the war. What the optimum interval for such tests will be after the reservoir becomes more stabilized has not yet been determined. It might be found to vary from one area to another. Results from these tests indicate that the average productivity index has increased about 27 pct and the gas-oil ratio has remained practically constant. The rate of change of both these variables appear to be decreasing.

Repair and Remedial Work

As mentioned previously, the Shallow Oil Zone is composed of several separate sand bodies. In some areas considerable pressure differential exists between sands. In others, certain sands have become wet while the others are still oil productive. Many of the old wells in the Tupman area were multiple-zone completions. Since they were drilled prior to electric logging, it is difficult to determine what sands are open to production. With the field in more or less a state of flux as it approaches equilibrium shut-in conditions, caution must be exercised in order not to prematurely plug off a sand that, although now wet, might in the distant future produce some oil. The early aim of this program is to isolate water to its own zone as much as possible by preventing migration through well bores. This migration occurs readily in the field because of the common occurrence of pressure differentials existing between zones.

The individual jobs will not be discussed, since they follow the more or less conventional pattern, but a summation of some of the results may be of interest. With regard to straight plugging for bottom water, the following degree of success has resulted from the indicated procedures: For water shutoffs on 36 recent jobs, 18 were considered completely successful, 9 still produce some oil and 9 stopped all production. This work increased total oil production from 889 to 962 bbl per day, an increase of 8 pct, and cut water from 2864 down to 104 bbl per day.

In comparing methods the following table shows results obtained.

	Number of Jobs	Successful, Per Cent
Cavity shots and cement plugs	18	60
Gun perforate and dump cement	10	50
Long knife perforation and cement	2	100
Cement shots	2	50
Intermediate plastic scabs	2	50
Plastic plugs	5	40

The number of jobs attempted in some of the methods may not be sufficient to warrant any definite conclusions as to their merit but it does indicate the trend. Further work will indicate more definitely what type best suits this particular field. This work was all done in wells averaging 3000 ft deep. Bottom-hole pressures vary from 20 to 1000 psi.

Wet wells in the field that might possibly hurt the reservoir have been kept on production but as they are successfully repaired they are shut in and added to the list for annual rotating test. Two repair strings are operating on this work. The average plug job requires about seven days. Possibly another year will be required to complete the program.

Gas-injection Program

Gas was first injected in the Elk Hills reservoir during the development and production period instigated by the last war. At that time the excess gas from oil production was injected into various parts of the reservoir to aid in pressure maintenance. At the cessation of hostilities and the resulting curtailment of production, this source of gas was no longer adequate.

Realizing the desirability of flush-production characteristics when the field is to be reopened for production, a long-range pressure-restoration program was inaugurated in January 1946. Dry gas from the upper gas sands is being produced from three wells and injected in the oil measures. The gas is produced at pressures varying from 300 to 400 psi and compressed for injection at 500 to 650 psi.

Injection takes place through five wells in the gas-cap area of the SS-2-M sand. The daily rate varies from 8½ to 10 million cubic feet. To the time of writing, a net volume of 3¼ billion cubic feet has been injected over and above the volumetric withdrawals during the period. The position of the gas cap as it existed at the start of the large-scale injection is shown as the dotted area on Fig 2. The hatched area represents the enlargement of the gas cap during the injection period. In both cases production having a gas-oil ratio greater than 1000 was considered as coming from gas-cap conditions. It may be observed that the gas cap is not enlarging uniformly, but is fingering badly in certain directions. This fingering may be correlated with permeability variations[4] of the reservoir sand with amazing success.

In order to observe the movement of the injected gas, helium is being used as a tracer. Apparently a helium concentration of 0.1 pct by volume is sufficient for this purpose. Helium in abnormal concentration has appeared in 30 wells since it has been used as a tracer. The fact that it is undetected in adjacent wells but is found in wells farther down structure indicates that considerable channeling is taking place. The injection pattern is altered from time to time to offset this condition.

The average datum pressure of the area that is expected to be repressured from the gas injection has increased from 612 to 697 psi for an average of 3.86 psi per month. Over the injection period 38½ MMcf was required to raise the pressure 1 psi. During the last four months, however, it has required 53.6 MMcf per psi and it is probable that the ratio will increase further with the greater volume of gas in the reservoir. Fig 4 shows the trend of the reservoir pressure in relationship to the net injection. It is planned to continue the

injection until the average pressure approximates 800 psi. To accomplish this will require an estimated total injection of 11 billion cubic feet, which at the current rate

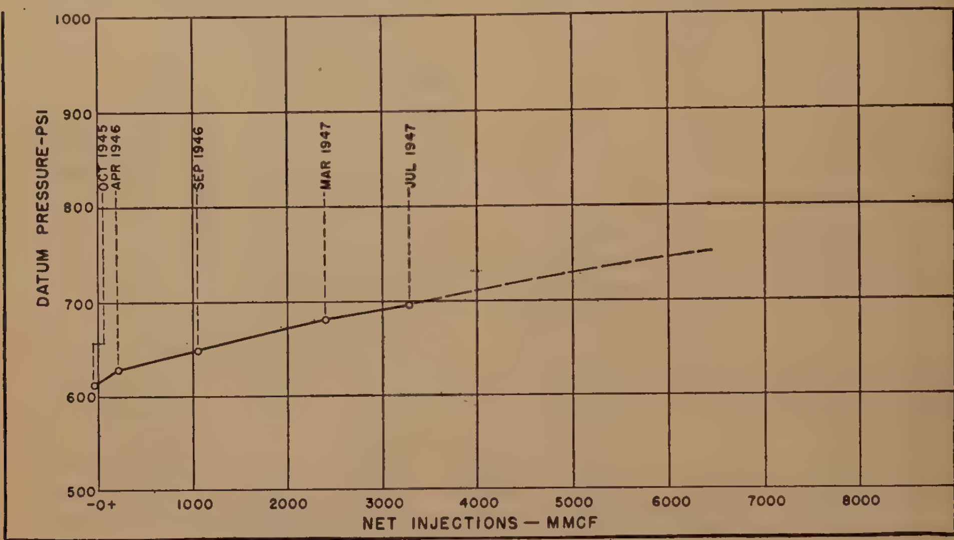

FIG 4—RESERVOIR PRESSURE VS. NET INJECTION.

of injection will require an additional 3½ years.

It is believed that the gas-injection project will permit the most expeditious production of oil when required, reduce production costs, and retard the encroachment of water into productive areas.

WATER-ENCROACHMENT STUDY

Prior to the formation of the Unit, the operators in the Tupman area found it to their advantage to prevent the water from encroaching up structure by producing it in the wet wells. Under the noncompetitive conditions now present in the field, and the fact that the field will be practically shut in for an indefinite period, it was deemed advisable to determine whether a water drive exists and, if so, the relative advantages of (1) permitting the water to encroach up structure into producing areas, or (2) preventing it from encroaching.

It was decided to select a fault block isolated as much as possible from the remainder of the field and observe the manner in which water encroached. The place chosen for the study is a wedge-shaped area in sec 26S, 27S and 34S, with fault boundaries on three sides and the northeast side open to the edge water. If these faults are competent pressure and fluid barriers, this offers an excellent opportunity to study the action in the area unaffected by the operations in other parts of the field. The majority of the wells in this area are completed in the SS-1 and SS-2 sands, but a few of the new wells at the south end are open to M and SM sands. The area also has the benefit of 1100 ft of structural closure. At the start of the project, the pressures in the upstructure producing area were from No. 200 to No. 450 lower than in the wet, downstructure area. This pressure differential offered ample opportunity for fluid movement if sufficient volume was present.

During the producing life of the wells in this area water has been produced with the oil as the wells went wet and the advance of water was retarded to an average hori-

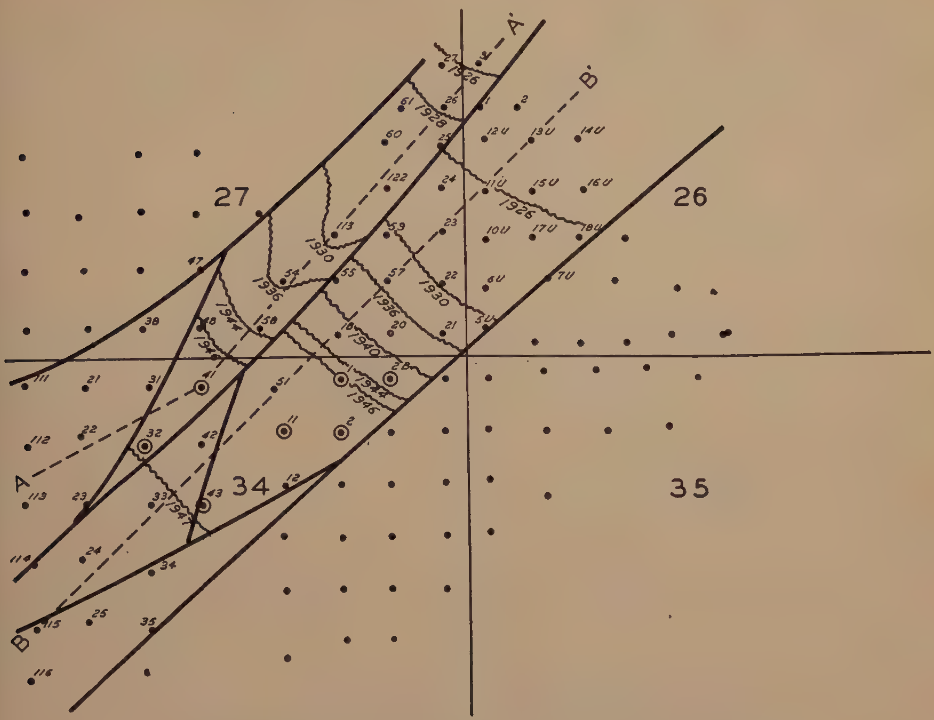

FIG 5—WATER-ENCROACHMENT STUDY, SECTIONS 26S, 27S, 34S.

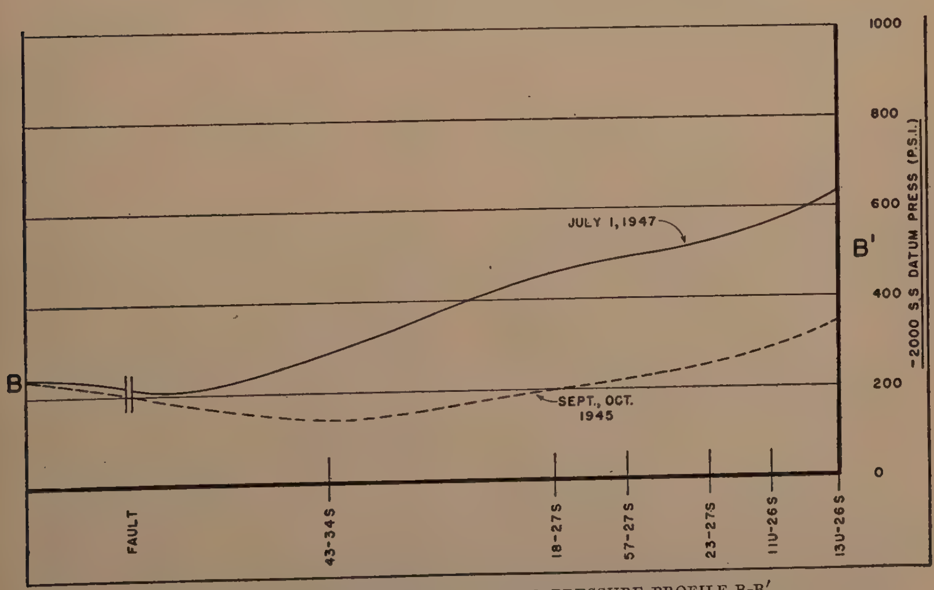

FIG 6—WATER-ENCROACHMENT STUDY, PRESSURE PROFILE B-B′.

zontal advance of about 100 ft a year during the 10-year period from 1936 to 1946. During the last half of this period as much as 5000 bbl per day of water was vation wells was decreased approximately 50 pct.

A study of the pressure profiles and edge-water map shows that the project has

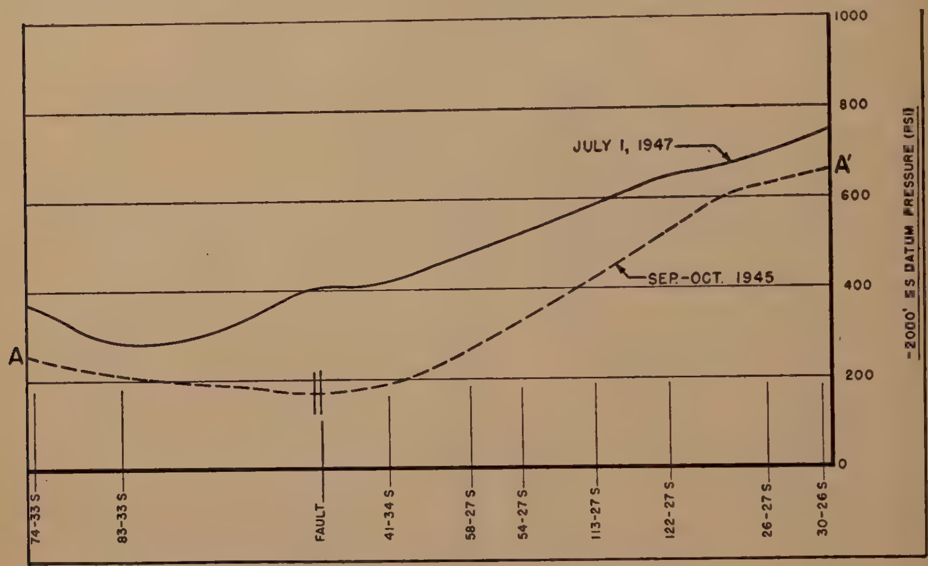

FIG 7—WATER-ENCROACHMENT STUDY, PRESSURE PROFILE A-A'.

produced, practically eliminating any encroachment. In October 1946, the downstructure wells were shut in, eliminating the production of 453 bbl of oil and 4564 bbl of water, a total gross fluid of over 5000 bbl per day. Seven upstructure wells were produced steadily as observation wells. Pressure contour maps and pressure profiles for the two fault blocks in the area were constructed about every six months. Fig 5 shows the progress of the encroachment of water upstructure. A water cut of 50 pct was used as a basis for the presence of edge water in the study and for constructing Fig 5. Fig 6 and 7 show the pressure profiles along dip sections of the area.

It was soon found that water movement upstructure was too rapid for effective flushing of the sands. The pressures upstructure from the producing observation wells also continued to fall. To offset these conditions the production from the obser-

definitely proved the existence of an active edge-water drive in these two fault blocks. This cannot be taken as a general rule for all fault blocks, however, as there is ample evidence that it does not occur in at least one other fault block in this end of the field. The profiles indicate that the pressures are increasing from downstructure toward the upstructure wells. Datum pressures in the shut-in wells have increased and the pressure fill-in has moved upstructure. There is no conclusive evidence to indicate that the upstructure area is contributing to the pressure build-up in the producing area of observation wells, so the improvement in production characteristics of these wells must also be attributed to the advancing edge water.

This much information would clearly indicate that a properly controlled water drive would improve the production characteristics of certain fault blocks where a water drive exists, but what effect this

water is going to have on the ultimate recovery, and whether or not it will damage the reservoir, is not yet clear. Volumetric calculations indicate that the water at its present rate of advance must have come up only a part of the sand members present to reach so far upstructure in the short period of observation. This has been substantiated by water that runs in wells that have recently become wet. These runs show that water is preferentially encroaching at the base of the SS-1 sand, possibly leaving considerable oil in the remainder of the sand behind. In view of this danger and the fact that water apparently is encroaching faster than the optimum rate, the production of some of the water downstructure is being considered. A new well has been drilled in the wet area to get information on the state of depletion of the reservoir sands. When the production tests of this well are completed it may throw some new light on the efficiency of water drive in this type reservoir.

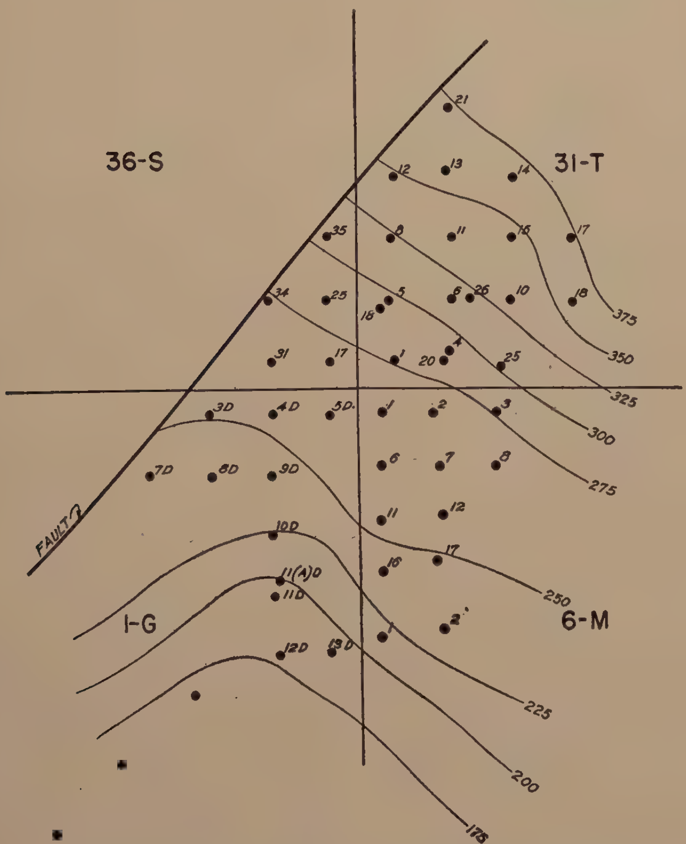

FIG 8—GRAVITY-DRAINAGE AREA, PRESSURE CONTOURS.

Gravity Drainage

To explore the advantages that might be derived by producing the field under gravity-drainage conditions, a portion of the field was set aside for such a study. This area, which is shown on Fig 8, offers an opportunity to produce a large quantity of water from the edge of the field and observe what effect this might have on the

production in both the area being dewatered and upstructure. This area is separated from other areas by faults or sand pinch-outs so the effects of the water production will be localized. The number of multiple-zone completions is small and there are wet wells downstructure from which to produce the water and clean wells upstructure for observation wells. The program included the making of pressure studies and profiles which showed a high datum pressure in the downstructure wet area and a large pressure sink upstructure into the clean well area. It was planned to reduce the datum pressure in the wet area by dewatering. This would establish a favorable gradient for the clean oil to gravitate downstructure.

When the program was started in the fall of 1945 about 2300 bbl per day of water was being produced, and this amount apparently just held the water back. To increase water production required larger tubing and pumps for some wells. Sand entering the wells at these high production rates gave much trouble and progress in stepping up the water production has been slow. At present about 3500 bbl per day of water with a small quantity of oil is being produced downstructure. With the addition of four more larger pumping units, it is hoped that this will soon increase to 5500 bbl per day.

Observation of the area so far has indicated that the pressure sink has filled in a small amount but other pressures have changed little. The conclusion is that the rate of water withdrawal is not yet high enough to give any marked change in the original condition. Although this project to date has not given much information in regard to gravity drainage, it has at least controlled the migration of water around the eastern nose of the structure.

Conclusions

The Elk Hills field, with its unusual operating conditions, offers an opportunity for actual field study of many oil-field problems that heretofore have been attacked only on a theoretical basis. The shut-in field should produce some situations not found in producing fields, and through a careful study engineers may find the answer to some of their most perplexing production problems. The present studies may or may not give conclusive answers to some of our questions and other similar projects may have to be initiated. The present projects are being conducted with care so that the conclusions will not be in error caused by mistakes in methods and procedures. The industry will be kept advised as these studies proceed and it is hoped that the technique of both producing and conserving the natural resources will be improved as a result of these studies.

Exploratory Drilling Program

Purpose and Scope of Program

An exploratory program has been in progress in the Elk Hills field since July 5, 1945. The project probably will continue for another two years. It is being carried on under the provisions of the Unit Plan Contract and Operating Agreement with the Standard Oil Company of California acting as operator.

The major purpose of the program is to provide a means of making a reasonable estimate of the recoverable oil contained in the known productive zones of Naval Petroleum Reserve No. 1. The program will also provide data regarding: (1) the potential productive rate of the two main oil measures, (2) the percentage participation of the Navy and the Standard in the productive zones, (3) a more exact delineation of the productive areas, and (4) the formulation of plans for the most expeditious development of the field when such is required.

Under the Unit Plan Contract, the responsibility for locating exploratory wells rests with the Engineering Committee.

This committee is composed of six members, three from each of the participants. At the outset of the exploration, it was estimated by the committee that possibly a total of 40 Shallow Zone wells and 24 Stevens Zone wells would be required to adequately explore these horizons.

Exploration of Shallow Zone

The Shallow Oil Zone at Elk Hills has produced approximately 190 million bbl of oil since its discovery. All this production prior to the exploratory program was obtained from the eastern half of the field. The western portion was not developed during the war, as the productive sand bodies were found to thin from east to west and to practically pinch out in the center of the field. The possibility remained, however, that the sands would thicken on the flanks or that new sands would be present on this major structural high. It was also deemed essential to establish the position of edge water in certain portions of the eastern field, particularly along the south flank, where some unusual reservoir conditions had been noted during the wartime development program. Exploration of the Shallow Zone was designed to supply this information.

The Engineering Committee recognized the impossibility of predicting the number of wells that would be required to explore the western portion of the field. The results of the first dozen or so wells were expected to determine the future requirements. It appeared, however, that at least 18 Shallow Zone wells would be required to test this large area even though they were all found nonproductive. Accordingly, the original project contemplated the drilling of 40 wells, realizing that a minimum of 18 wells might fulfill the purpose of the program.

Formations Encountered

The formations overlying and associated with the oil measures in the Shallow Oil Zone do not offer any unusual difficulties in drilling. The surface formation is Tulare of Pleistocene age. Consisting of unconsolidated sand, light gray clays, silts, gravels, and marls, it has a thickness of 800 to 1200 ft. The Tulare formation is underlain by the San Joaquin clays, the top of which is designated as the top of the Pliocene. It consists chiefly of nonmarine deposits of gray, green and brown claystones and shales, gray silts and friable sands. The sand bodies contain dry gas at the higher structural positions. The thickness of the formation varies from 1200 to 1800 ft. At the base of the San Joaquin clays is the *Scalez* oil zone, which has provided the major portion of the production of the field. This zone includes three separate sand bodies, the As, SS-1 and SS-2. The upper two sands are not continuous over the entire developed portion of the field. Immediately below the Scalez oil zone lies the Etchegoin formation. It is normally 1800 to 3000 ft thick and consists essentially of marine sediments of dark gray shale and claystone, gray to green silts and numerous sand bodies. Near the top of this formation occur the Mulinia sands which are important oil-productive sands in the recently developed portion of the field. Below these sands occur the Bittium, Wilhelm, Gusher, and Calitroleum zones, which have been productive in adjacent areas but had not been thoroughly tested in the Elk Hills prior to this program. The base of the Etchegoin formation represents the base of the Pliocene.

Drilling Program

The Shallow Oil Zone is defined in the Unit Plan Contract as "all oil or gas bearing formations of Pliocene Age above the Reef Ridge Shale." This interval normally includes about 4000 ft of section lying at a depth from 1000 to 5000 ft. The drilling program for the first wells drilled in any general area provided for the coring of all possible productive horizons in the above-

described interval in reduced hole, and the drill-stem testing of each zone separately if the cores, mud log and electric log so warranted. On one of the first wells nine drill-stem tests were made of separate intervals. This type of exploration is naturally time consuming and expensive but was deemed necessary to gain the information on the various possible productive horizons in different portions of the field.

After this information was gathered for the different areas, the mud logging and much of the coring and testing was eliminated in later wells.

Casing Program

Various casing programs were used depending on the structural location of the well and the objective. In the first wells, 11¾-in. casing was cemented at about 1200 ft, and a 7-in. pre-perforated combination string was cemented through ports over the lowermost productive interval. Upper zones could then be tested by plugging off bottom and gun perforating if so desired. Gun perforating for production, however, has been kept to a minimum. In a good many areas of the field, sand production and plugging of perforations were found to be excessive with this type of completion.

In the latter stages of the program, when more was known about the individual areas and the wells had definite objectives, many were completed with 7-in. water string and 5½-in. liners in lieu of the combination string.

Cost of Wells

It was estimated originally that the total cost of drilling and equipping the Shallow-Zone exploratory wells to produce would be approximately $60,000 apiece. This figure was found to be adequate for the first wells, in which considerable coring and testing was deemed necessary. In the later wells the cost was considerably less, the average being about $48,000 per well. This represents unit costs of roughly $12 per foot and $1400 per day when considering the total cost of drilling and equipping the well in relationship to the total depth and drilling days.

Exploration of Stevens Zone

Prior to this exploratory program the Stevens Zone was an unknown factor in the Elk Hills. Although regarded by many as the largest unexplored potential oil zone remaining in California, very little had been done to determine its productive value. Nine wells had been drilled to and tested the Stevens Zone on the Elk Hills structure. Three of these resulted in commercial producers, two were marginally commercial and the remaining four were nonproductive. The three good wells—namely, 342-31S (discovery well), 362-31S and 344-33S—were drilled in 1940 to 1942, in the middle eastern portion of the Reserve. They indicated that production could be expected from both sand and fractured shale but, because of the vast area involved, gave no indication of the probable ultimate recovery or extent of either. The program was designed to obtain the required information and to determine the existence, if any, of other productive intervals in the Stevens Zone. The Engineering Committee originally estimated that 24 wells would be required to supply this information.

Formation Encountered

The Stevens Zone, as defined in the Unit Plan Contract, consists of "all oil and gas bearing formations of Upper Miocene Age within the stratigraphic interval between the top of the Reef Ridge Shale and the top of the Valvulineria Californica or associated faunas of Middle Miocene Age." This definition includes more interval than that generally considered as the Stevens Zone. The definition was made so all-inclusive to eliminate the necessity of

setting up a new zone of participation for any stray oil measures that might be found between the Shallow and Stevens Zone.

The Reef Ridge formation, lying immediately below the base of the Shallow Oil Zone, is quite similar in lithology to the basal Etchegoin, and because of this it has been difficult to pick the top of the Miocene. The Reef Ridge is about 800 ft thick and consists of dark gray to brown shale. In the very western portion of the field a productive sand has been found which is possibly at the base of the Reef Ridge.

Below the Reef Ridge is the "Hard Brown Shale," which consists of about 2500 to 3500 ft of hard, dark brown siliceous shale with thin stringers of chert. The *N*-point, a marker from the electric log, occurs about 100 ft below the top of the cherty shale. The Stevens sand when present exists about 300 ft below the *N*-point. The productive sand thickness has been found to vary from 0 to 500 ft.

The drilling and testing of the Stevens Zone has been a slow, tedious process. As in other southern valley fields, considerable cherty shale overlies the productive measures of the Stevens. In certain portions of the field this same hard cherty shale in a fractured condition serves as a reservoir for the oil. In some wells it has been necessary to penetrate 3000 ft of this hard formation to completely test the Stevens Zone.

Drilling Program

The Stevens Zone wells are generally programmed to core through and drill-stem-test the productive measures of the Shallow Oil Zone on their way to the Stevens. Although this requires about 4 to 6 days added drilling time, the information gained usually substitutes for a Shallow Zone well. On completion of testing the Shallow Zone, the wells are drilled to a depth estimated to be about 200 ft below the top of the cherty shale. During this process the cuttings and drilling rates are watched for structure control. Wells usually are cored ahead in reduced hole from this point in about 300-ft stages to the base of the Stevens, running electric logs on each interval and drill-stem-testing if the cores and electric logs indicate such action is warranted.

As mentioned previously, production has been obtained from fractured portions of the hard cherty shale. Core recovery in these intervals is very poor, probably because of the fractured nature of the formation. Electric logs have not been diagnostic in predicting the fluid content or permeability of the shale reservoir. Mud logging has been unsuccessful in predicting productive measures in the Stevens shale. The drill-stem test, though adding greatly to the cost of the wells, has been found to be the most important yardstick in determining productive horizons. In making drill-stem tests, straight hole packers have been tried both in the Shallow and Stevens Zones, with little or no success. Insurance of successful tests necessitates the "rat-holing" and subsequent reaming of the entire productive Stevens section.

Diamond Coring Equipment

Very slow drilling rates are made in certain parts of the cherty shale section. The sand also offers unusual resistance to the drilling bit. In order to more readily penetrate these formations, diamond core heads were used to determine their adaptability in the Stevens Zone. At the time of writing this report, four 6⅜-in diamond coring bits, each of slightly different design, have been tried. The individual bits made from 23 to 205 ft before they were returned for salvage. The average diamond bit made 88 ft of hole compared with an average of 12 ft made by 8½-in. Rock Head coring bits in the same type of formation in the same hole. The penetration rate was 2.3 ft per hour for the diamond bits against 1.1 for the average rock bit. Since it was found that the one particular design operated much better than the other, it is expected

that an even better showing will be made in the future. The best estimate of the economies of the two types of coring bits indicates that the "time plus head" cost of using the diamond bit is about 50 pct of that for the rock bit. Another fact which can not be readily evaluated is the increased core recovery obtained by the diamond bit. It has been possible to obtain good samples of the fractured shale which were unrecoverable by other means. It should be realized that these figures are based on only limited use of the diamond bit and may not be representative for a more prolonged period.

Casing Program

As in the Shallow Oil Zone, no set casing program has been followed. The design of the casing strings has been altered to meet the variety of subsurface conditions encountered in the Stevens. During and immediately after the war, it was necessary to use whatever casing was available. Conditions permitting, it was found desirable to set a water string sufficiently large to permit "rat-holing" ahead in order to obtain drill-stem tests with cone packers. In areas where the Shallow Zone was productive a protective string was usually set through the sands. A normal Stevens casing program might be as follows: 18 in. of ⅝ cemented at 200 ft; 13 in., ⅜ cemented at 3600 ft; 9 in., ⅝ cemented at 6500 ft; 6 in., ⅝ liner 6450 to 6800 ft; perforated 6520 to 6800 ft; 60 mesh.

Cost of Wells

As might be anticipated from the type of formations encountered, and the drilling and testing program utilized, the costs of wells in the Stevens Zone are unusually high. The original estimate was $250,000 per well. While many of the wells were less than this, prolonged fishing jobs in others have raised the average to about $280,000. This indicates unit costs of $35 per foot, or $1300 per day. Here again the cost represents total drilling and equipping charges. It is interesting to note that the cost per foot is more than twice that of wells in the Shallow Zone while the cost per day is actually less.

Results of Program

The results of the exploratory programs in both the Shallow and Stevens Zones are interesting and, to the present time, appear to be fulfilling the purpose for which they were intended.

Shallow Zone

Prior to the exploratory program, very little was known regarding the stratigraphy and structure of the Shallow Oil Zone in the western half of the Reserve. In the developed eastern portion, production has been derived from five separate sand bodies which occur in an interval of about 300 ft and aggregate a maximum thickness in any one area of about 140 ft. During the wartime development the sands were found to thin from east to west, and the top sands disappeared one by one in that direction. A total of only about 10 ft of sand was present in the SS-2, M and SM at the western limit of development.

Well 48-26R, the first in the Shallow Zone under the exploratory program, was spudded July 19, 1945. Other drilling strings went to work on wells 42-25R, 42-32R, 42-3B and 48-18R soon thereafter. A maximum of six drilling strings were used in the operation at the start. The number of strings was gradually reduced. Only one shallow string has been operating since March 1946.

As of the time of writing this report, 35 wells have been drilled in the Shallow Zone under the program. Of these, 24 are oil productive, 3 are gas wells and 8 are abandoned. One well is now drilling and it is probable that one additional well will complete the program. The wells already drilled demonstrate, among other things, that the relatively thick sand bodies found in the eastern part of the field do not exist

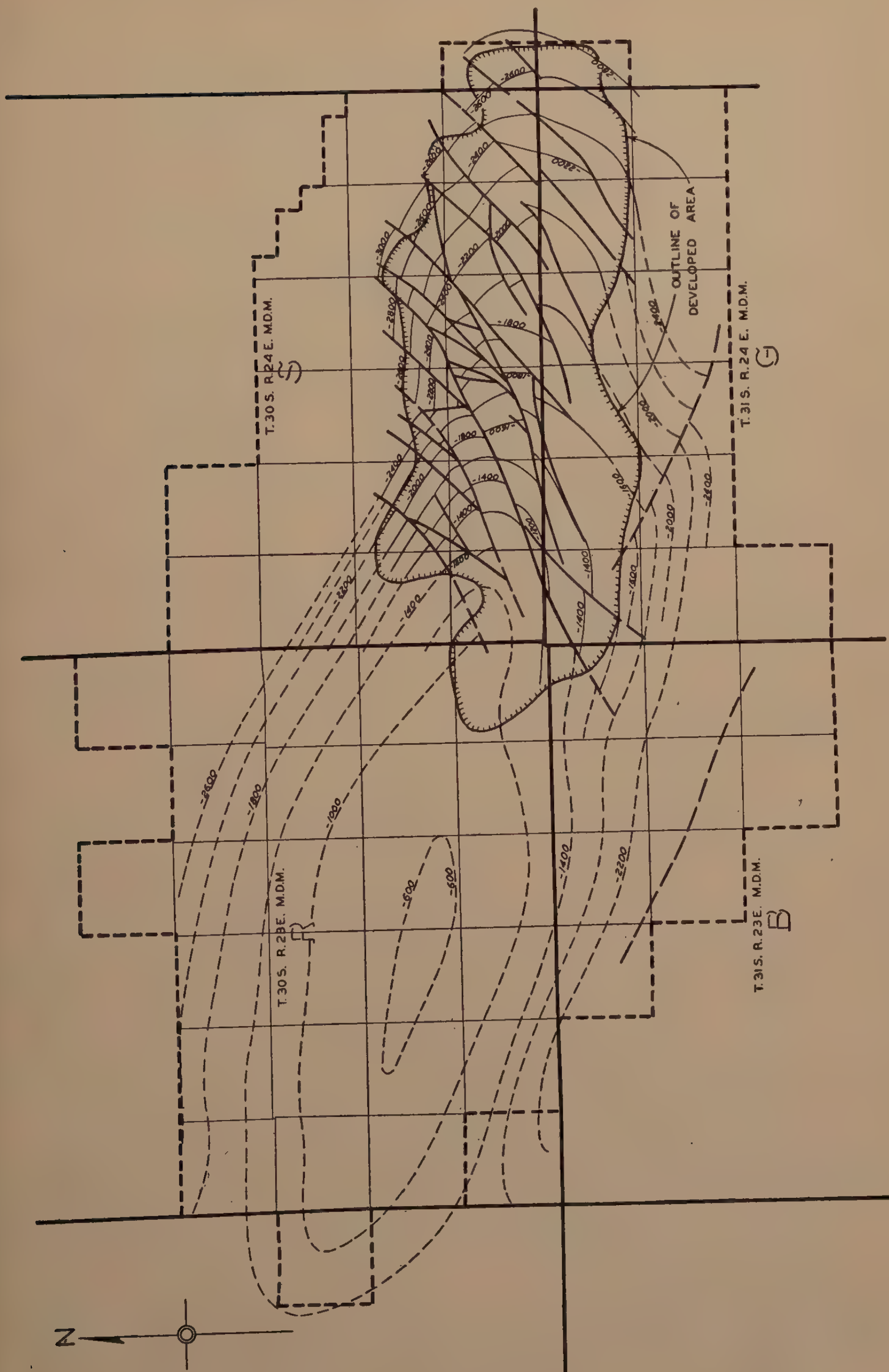

FIG 9—STRUCTURE MAP OF SHALLOW ZONE PRIOR TO EXPLORATION.

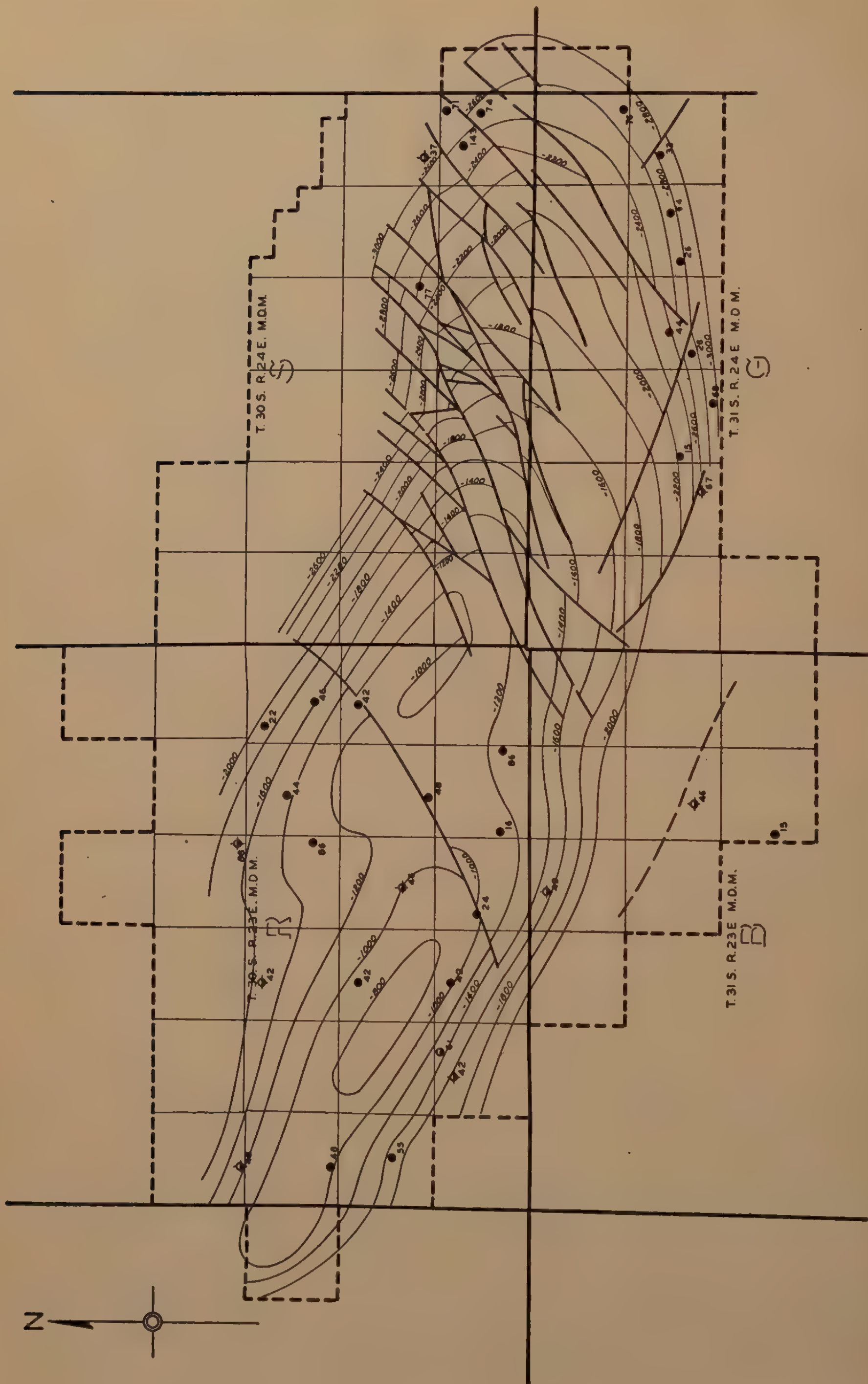

FIG 10—CURRENT STRUCTURE MAP OF SHALLOW ZONE.

in the western portion. Although production has been obtained in this area from what apparently are lenses correlative to the SM, Bittium and Wilhelm sands, the reserve of oil so established is minor in comparison with that existing in the eastern half of the field.

The interpretation of the structure prior to the exploratory program and the current interpretation are shown on Fig 9 and 10, respectively. Although there are several irregularities of the structure which were not originally predicted, the configuration is generally conformable to that found by drilling. Considering the scarcity of the data on which the original map was drawn, the interpretation was reasonably good.

The productive areas proven in the Shallow Zone under this program are shown on Fig 11. The combined newly proven areas total about 4000 acres containing an estimated 57 million bbl of recoverable oil. Approximately 30 million of this reserve was established by drilling along the south flank of the eastern field. As mentioned previously, an unusual condition had been found to exist in that area. Former drilling had not located edge water along the south flank in the SS-1 sand. Relatively small producers curtailed drilling in that area. This seemed unusual, as the sand characteristics were as good or better than the average of the field. Exploratory drilling has now indicated that the low productivity was a result of pressure depletion and that the edge water existed considerably farther south than had previously been supposed. Although of low pressure, this new area is believed to contain considerable recoverable oil, and wells of about 100 bbl per day can probably be attained under controlled drilling and completion procedures.

Stevens Zone

The first Stevens well under this program, 342-6G, was spudded on August 30, 1945. It was followed by well 382-34R a few days later. A maximum of six drilling strings was used at any one time. They were reduced to four in May 1946 and have remained at that number. At the time of writing, 11 wells have been drilled to and made adequate tests of the Stevens. Eight of these resulted in commercial producers. The remaining three were found to be nonproductive in the Stevens. Two of these, however, can be completed as producers in the Shallow Zone. It is estimated that another 15 wells will be required to adequately explore this zone.

The Stevens wells in the Reserve prior to the exploratory program furnished little information regarding the stratigraphy or the structure of the Stevens Zone. As in the Shallow Zone, the data available pertained chiefly to the eastern portion. The geology of the western portion was entirely speculative. One of the first wells, 382-34R, was located in what was believed to be a very favorable location on structure, but the results of this early well indicated that the structure at the Stevens horizon was more complex than had originally been believed and was not conformable with the structure at shallower depths. The current interpretation of the structure is shown on Fig 12 and indicates that instead of one single anticline at least three separate closures exist. The eastern anticline (31-S area) has a known oil closure of about 2500 ft, the middle structure (29-R area) has about 1000 ft and the smaller extreme western structure (24-Z area) exhibits a proved productive closure of 1250 ft. Production in the 31-S area has been derived from both sand and fractured shale. The productive sand thickens from about 40 ft in well 362-25R to possibly 500 ft at well 326-35S. The productive shale thickens in the opposite direction from 0 at well 337-34S to 800 ft at 368-25R.

By use of the diamond coring head, small samples of the fractured chert were recovered, permitting for the first time an inspection of the appearance of the shale

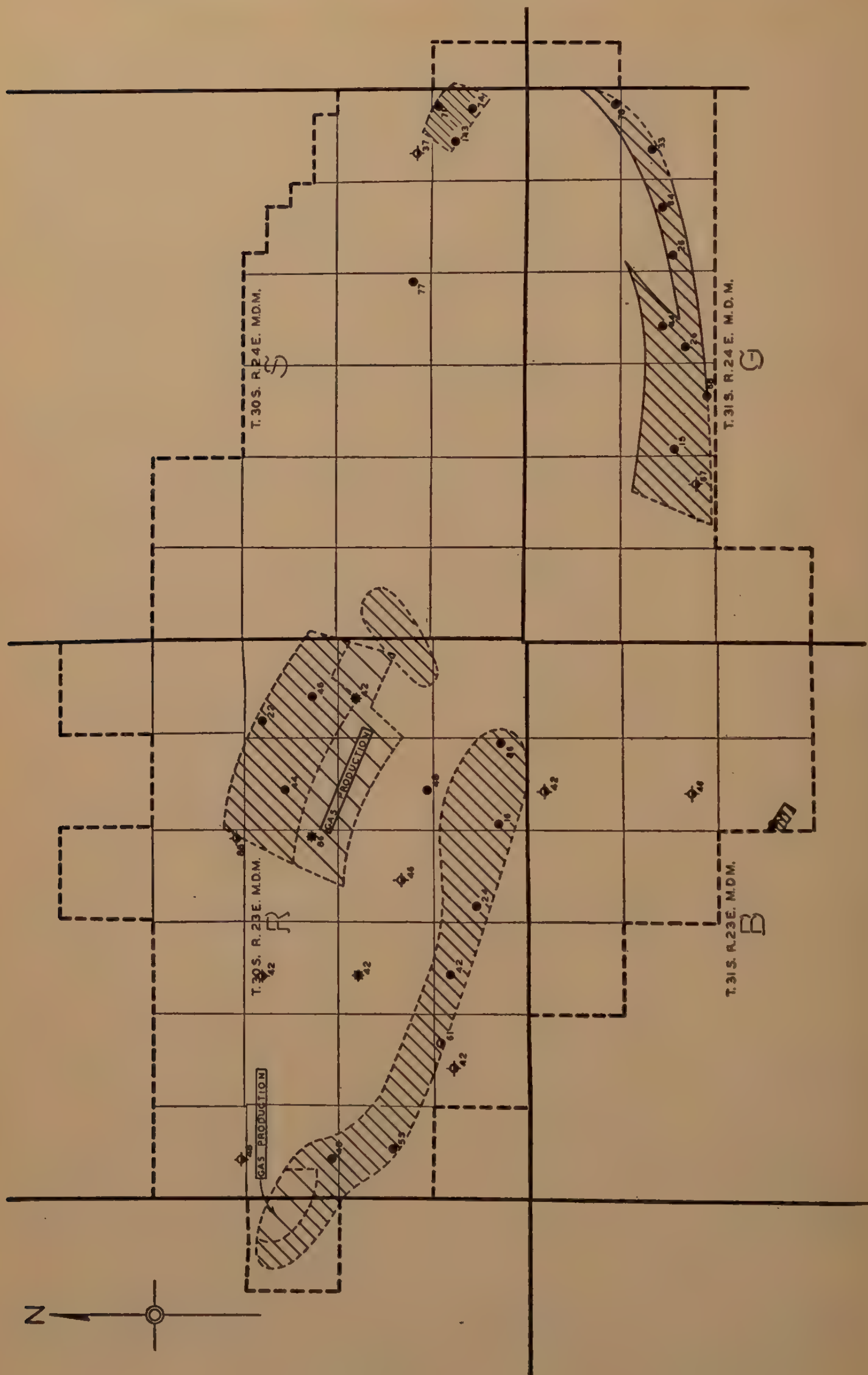

FIG 11—NEWLY PROVED AREAS, SHALLOW ZONE.

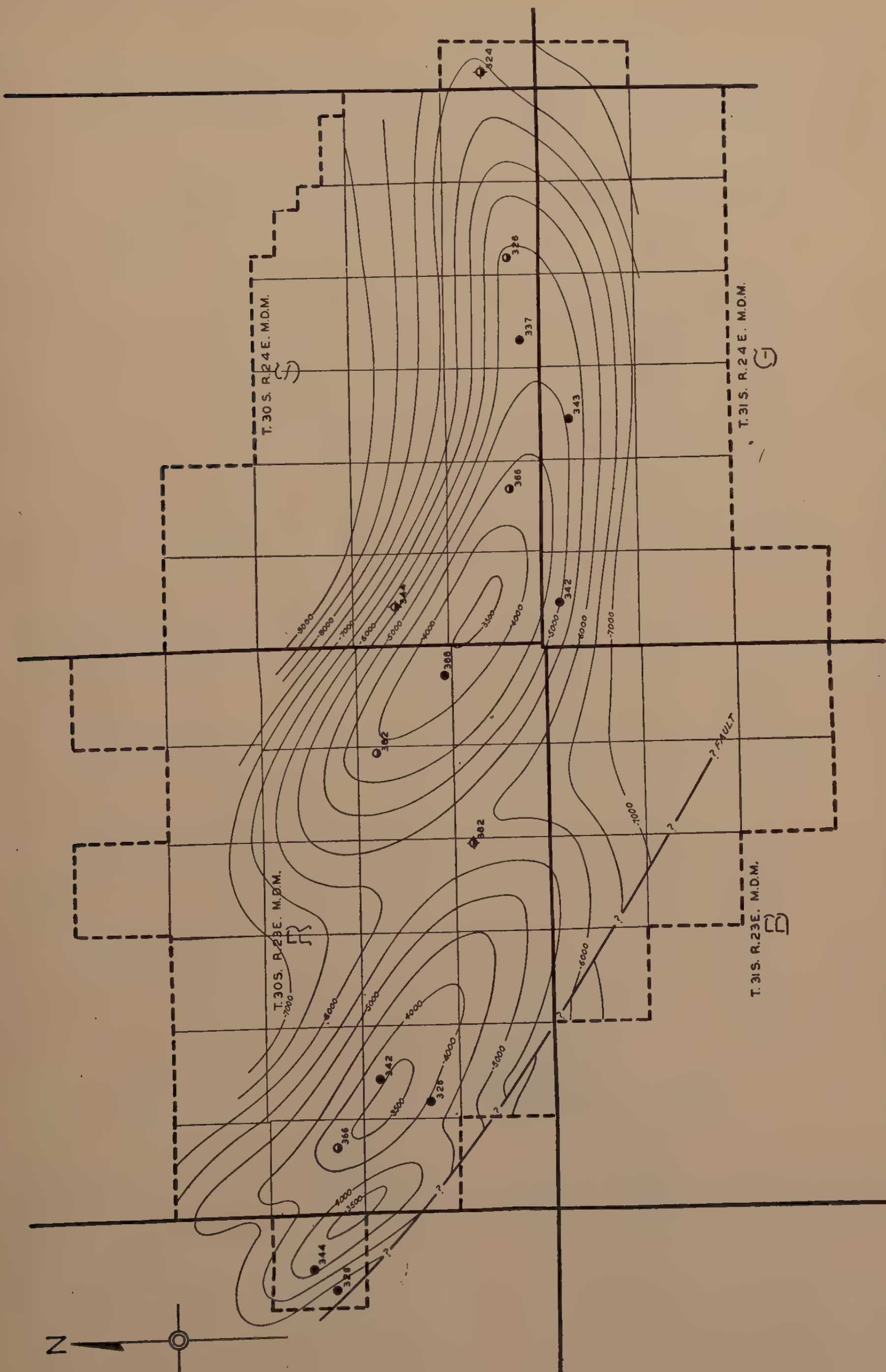

FIG 12—CURRENT STRUCTURE MAP OF STEVENS ZONE.

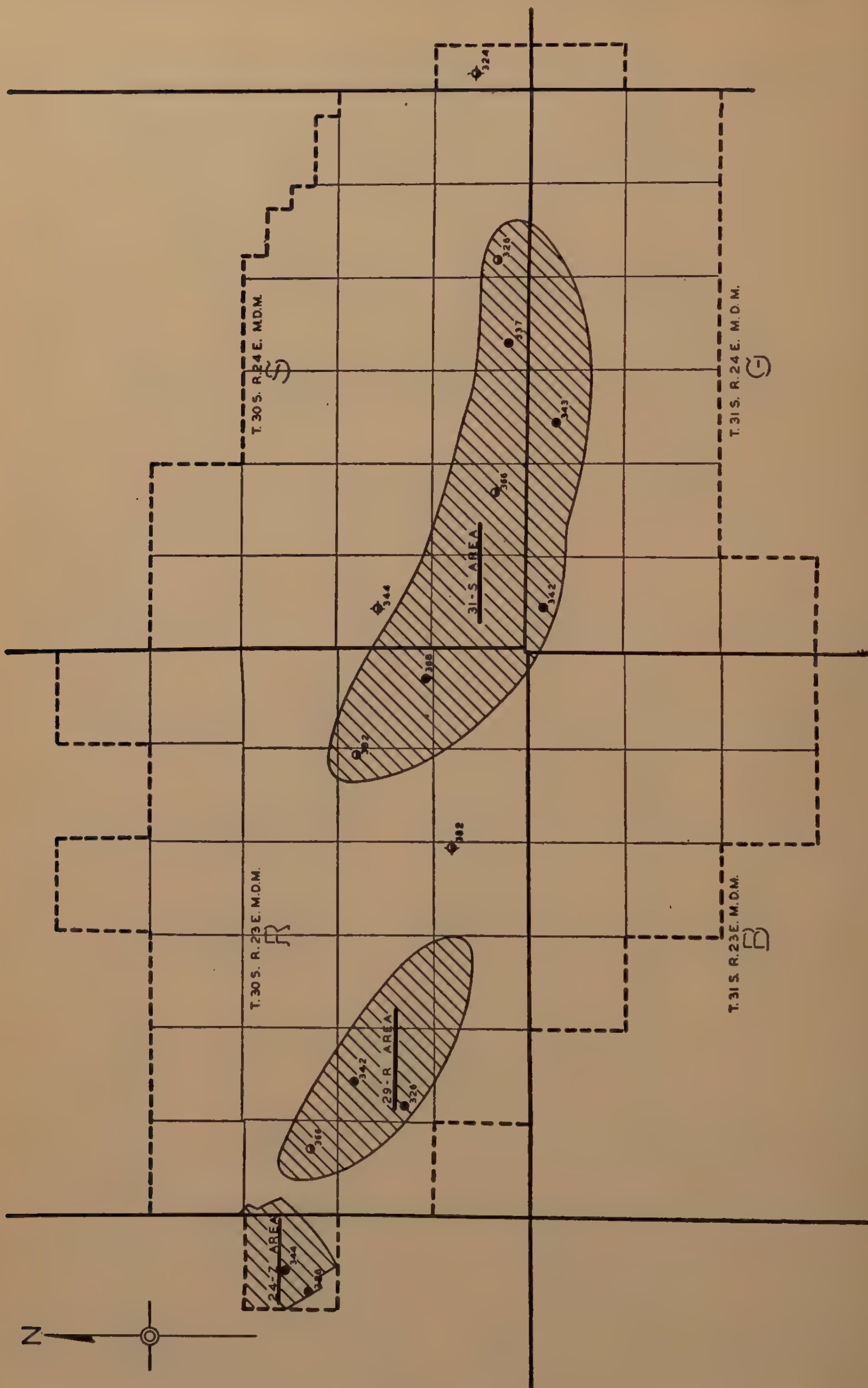

Fig 13—Proved areas, Stevens Zone.

reservoir as it apparently exists "in situ." The samples at first glance appeared as an ordinary, hard, siliceous shale, but on closer inspection fractures were observed running roughly at right angles to each other. When an attempt was made to pick up a sample by hand, it would break up into numerous cube-like pieces approximately ½ in. across. Residual oil could be observed in the fractures through the core. It is amazing that samples of this type material could be recovered in an apparently undisturbed condition.

Production from the 29-R area apparently comes solely from fractured shale, having a thickness of about 450 ft. The productivity of the shale wells appears to vary with their position on structure. Higher productivities are demonstrated by the wells near the axes of the structures. This would appear to indicate that the permeability exhibited by the shale is a result of fracturing created by the folding of the beds. The greater the degree of movement, the greater the resulting permeability.

The production from the 24-Z area is derived from two separate sand bodies aggregating a maximum observed productive thickness of 350 ft. The top sand is not readily correlative with any other known producing sand. Lying directly on the top of the hard, cherty shale, it is apparently younger than the Stevens sand in the 31-S area. The fossil and foraminifera markers used in other parts of the field are not present in this area, however, so the relative age of the two sand bodies has not been definitely established. The lower sand occurs approximately 100 ft below the top of the cherts. To differentiate the two, the upper sand has been termed the 24-Z sand and the lower is merely termed Stevens sand. The extent of these sands is unknown, but it is generally supposed that the source is from the northeast.

The outlines of the productive areas are shown on Fig 13. The total productive acreage is approximately 7500 acres, 6400 of which have been proven under this program. The ultimate recovery to be expected from the fractured shale is a great uncertainty. On a conservative basis, however, the reserves of the Stevens Zone are placed at about 250 million barrels.

Conclusions

It is believed that the results obtained from the Stevens exploration justify the high cost of carrying on this project. A large volume of oil has been added to California's oil reserve. In addition, it has been demonstrated that it is possible to derive production from the hard, siliceous shales of the Miocene. The possibility that this condition exists in other fields of the southern San Joaquin Valley may open up a new field for investigation in the never ending quest for oil.

Acknowledgments

The writers gratefully acknowledge the contributions and support offered by Commodore W. G. Greenman, USN, Mr. H. P. Stolz and Captain V. H. Wilhelm, USNR, at whose suggestion this report has been prepared. Acknowledgment is also expressed to the Superintendent and members of the Unit Operation Staff who were responsible for the collection of much of the presented data. Appreciation is expressed to the Navy Department and the Standard Oil Company for the permission to present this report.

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LEGEND FOR TOWNSHIP ABBREVIATIONS

Designation	Township	Range MDB&M
B	31S	23E
G	31S	24E
M	31S	25E
R	30S	23E
S	30S	24E
T	30S	25E
Z	30S	22E

DISCUSSION

W. S. EGGLESTON*—One thing in this paper that has struck me rather forcefully is the marked similarity of the interpretation of the fault pattern prior to exploration, Fig 9, and the current structure map of the Shallow Zone, Fig 10. This similarity puzzles me. Subsurface faulting is very difficult to trace and outline, and when a fault map does not change over the years with drilling it indicates a very unusual set of circumstances.

It would seem to me that this is important, since many of the production experiments are based upon controls within isolated fault blocks.

I also note that the structure map of the Stevens Zone is singularly free from faulting. I assume that this is due to lack of control; however, I would predict that as development continues a system of faulting will be developed for the Stevens Zone. Without considerable faulting at depth which affects the Stevens Zone it is doubtful that the fractured siliceous shales and cherts mentioned in the paper will be highly productive.

It is reasonable to assume that if the cherty interval is determined to be commercially productive the most prolific wells will be found within the influence of faulting.

It is stated in the paper that mud logging has been unsuccessful in predicting productive measures in the Stevens shale. I would like to know whether it has been successful in predicting productive measures in either the shallow sands or the Stevens sand.

It is interesting to note that the productive thickness of the fractured shale or chert of about 450 ft compares favorably with such fields as Gato Ridge and West Cat Canyon.

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R. P. MANGOLD*—The authors are to be commended for their excellent account of the history of development at Elk Hills and description of production and exploratory projects now in progress. The unusual opportunity afforded at Elk Hills for the study of reservoir processes is most fortunate and the willingness of the Navy Department and the Standard Oil Co. to publish the results of these projects for the benefit of the oil industry is greatly appreciated.

A number of questions arise and I would appreciate obtaining the authors' answers or interpretations, if not now, perhaps in a subsequent paper when more data become available. It was mentioned that the sands in the Shallow zones have a connate water content approximating 30 pct, presumably corresponding with the average permeability of 1500 millidarcys. This saturation is considerably above what is generally considered typical of California oil sands having such a permeability, therefore it would be appreciated if the basis for the 30 pct figure could be given. If an interstitial water content of this magnitude for 1500 millidarcys permeability is substantiated by a reasonable amount of data, it will assist in explaining some of the anomalies between actual practice and the results predicted from reservoir calculations employing this basic quantity.

The 27 pct increase in productivity indexes of the wells in the essentially shut-down portion of the field is interesting and rather surprising, since it was not accompanied by an alteration in gas-oil ratios. Presumably the increase in productive ability might be due to changing fluid saturations occurring in the sands during the period of limited offtake, but this would be expected to be accompanied by reduced gas-oil ratios. Or perhaps it might be due to the influence of larger individual well-drainage areas than when all wells are producing. Do the authors have an explanation for this increase in productivities?

The results of the bottom-water shut-off jobs suggest that little if any oil production

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was being obtained from the intervals producing water. This is a quite important condition to know, if true. Has there been much intermediate or top water trouble; if so, what success has been obtained in shutting it off, or may it be inferred from the tabulated results that the two intermediate plastic scab jobs are the only ones of this type?

With regard to gas injection, has it been possible to ascertain whether the observed increase in pressure is a reflection of pressures in the gas-cap sands only, or has there also been a comparable increase in pressures in the essentially oil-bearing layers? If not, there may be a circulation of fluids between different intervals with perhaps undesirable effects. Some surprising pressure differences between several adjoining intervals of a producing zone have been observed in different fields, which lead to the conclusion that such circulation of fluids is a reality of appreciable magnitude and must be coped with. Do the authors consider that gas-cap expansion, which apparently is scheduled for substantial further increase, will be sufficiently effective in improving production performance in other areas to balance the loss of recovery from wells presently or formerly oil productive, but which are now being overtaken by the gas cap? Presumably wells in the expanding gas-cap area will be relatively useless in the future as oil-withdrawal points.

In connection with the water-encroachment study and the statement that it is not yet known whether water will damage the reservoir, this might be determined in part by a study of productivity-index trends before and after water reaches a well. Thus, a substantial decrease in the productivity index after a well has become wet would suggest a damaging effect of the water on the producing ability of the oil sands. Have any such observations been made as yet?

The results of the gravity-drainage experiment will be of great interest and valuable application to the industry, perhaps demonstrating in actual practice the relative merits of this versus the water-drive recovery process. The publication of these observations will be awaited with much interest.

M. C. Eastman (author's reply)—Mr. Eggleston's remarks pertaining to the difficulty of interpreting subsurface faulting apply very well to the Elk Hills field. In the particular case he pointed out however, the complex fault pattern shown in the eastern portion of the field of the Shallow Oil Zone was based on the data obtained from the relatively close spacing of wells in the developed area. Since the exploratory program was carried on chiefly in the remaining portion of the field, there were no additional data on which to change the fault picture in the area to which he referred. It is possible that the remainder of the field is faulted to a like extent in the Shallow Zone, but lack of control does not permit such a refinement.

The Stevens Zone may also be badly faulted, but at the present time we believe it will have an entirely different fault pattern, for the Shallow Zone faults appear to decrease in throw in the basal Etchegoin formation and die out at the top of the hard shales of the Miocene. A considerable number of fractures and slickensides are observed in the productive shale so it may be that faulting is responsible for the permeability exhibited by the shale. Results of the wells to date definitely indicate that the greater productivity is obtained from wells near the axes of the structures.

Mud logging has been reasonably successful in predicting oil and gas sands in the Shallow Zone, but many of the shows recorded were nonproductive, because of the low permeability of the sands and silts encountered. Insufficient experience with mud logging in the Stevens Zone prohibits conclusions as to its adaptability in that zone.

F. L. Ruhlman (author's reply)—With respect to the amount of connate water in our Shallow Zone, the following applies. When a curve of permeability versus percentage of connate water is plotted using all the available samples and from this curve the percentage of water for a 1500-millidarcy sample is taken, a figure of approximately 20 pct connate water is obtained. However, an average figure for connate water calculated by just averaging the results obtained on samples gives a figure of 30 pct, which is considerably higher. This is because there are more sands of lower permeabilities than high permeabilities. We feel that our data for connate water are fairly accurate, since they are the result of core-analysis work on nine wells drilled with oil-base mud. A

curve of these data from the oil-base wells lies as a straight line on log-log paper with 10 pct connate water corresponding to 4000 millidarcys and 70 pct connate water corresponding to 20 millidarcys.

With regard to the figure of 27 pct increase in productivity indexes, this perhaps is a little misleading. It is an average figure and was brought up by a few big producers which had an exceptionally high increase. The figure for gas-oil ratio is only an average figure and many wells did have a reduced gas-oil ratio. Since the field has previously been produced below the bubble point, we feel that there has been some readjustment and that the residual gas has been compressed by the entry of more fluid because of readjustments in the field. This should make more oil available at a lower gas-oil ratio when put back on production.

With regard to remedial work; we have in some cases lost oil production in shutting off water, particularly so when production is obtained from a single sand. Some wells are completed in two or more sands having different pressures. We think that in some cases where the higher pressure sand is wet a shut-off in this sand permits some production from the lower pressure sand that we did not have before remedial work began. To date we have had only a small amount of top and intermediate water. The assumption that the two intermediate plastic scab jobs were the only ones of that type to date is correct.

With regard to the gas injection program: The pressures represent averages of the whole area and include both gas-cap wells and wells without gas cap. We do find gas migrating from the SS-2 Zone, into which the gas is injected, into the SS-1 Zone just below. We feel that the area as a whole will benefit sufficiently from the repressuring to more than offset the loss sustained in captured wells. It is believed that many of the wells that have turned to gas will again be oil productive as the gas-oil interface approaches a more horizontal position.

Our data on the effect of water on the reservoir are limited but we do find in one well a sharp reduction in productivity index after water entry. This is what normally would be expected, considering that experimental research indicates that the permeability to oil falls sharply with water entry and the increased permeability to water increases only gradually with water entry. We should therefore expect an initial fall in gross productivity index with a later gradual increase in gross productivity index, and this so far has been true.

Control of Conventional and Lime-treated Muds in Southwest Texas

By E. H. Lancaster, Jr.,* Member AIME, and M. E. Mitchell, Jr.*

Abstract

A mud-conditioning program found to be very effective for drilling and completion operations on routine field wells requiring relatively short drilling time involves a moderate alkaline-tannate-bentonite treatment resulting in an ultimate filtration rate of 10.0 cc or less (API test). Mud weight schedules are planned from pressure information on completed wells in producing reservoirs and drill-stem test data obtained on other zones not being produced at present. In general, terminal mud viscosities average 45 sec (Marsh). This value has been found to be sufficient to remove cuttings from the well bore on the average well, with the slush pumps in general use on the rigs.

On field wells requiring drilling times in excess of approximately 30 days, an alkaline-tannate-lime-bentonite treatment has been effective in maintaining desirable viscosities and filtration rates with a substantial reduction in chemical costs. This system has shown particular advantage on heavily weighted muds and those with abnormal flow-line temperatures.

For the most part, the chemical treatment utilized in wildcat drilling follows closely the program used on field wells, depending on depth and duration of drilling operations. Wildcat mud programs are planned from information available from various geologic and operational sources, taking into consideration the possibility of encountering mud problems of a special nature in the wildcat area. Careful planning of wildcat mud programs has proved to have definite value in avoiding most serious mud problems.

An analysis and recommended treatment are presented on several special mud problems which have been encountered in the area in the past. Those problems discussed are lost circulation, blowouts, sloughing shale, excessive chloride contamination, sulphate contamination, and prevention and correction of cement contamination.

Introduction

Drilling-mud control in the Southwest Texas area, in general, does not involve the multiplicity of problems encountered in other coastal areas. For instance, it is rare that a mixture of problems such as lost circulation, abnormal pressure, severe sloughing shale, and others, occurs on one well within close enough limits in vertical depth not to be taken care of by a sensible casing program, together with a relatively clear-cut mud program. There are conditions such as the fairly widespread occurrence of abnormal pressure in the lower Frio and Vicksburg zones, and the tendency for sloughing shale in the Jackson section which make for rather expensive mud control. However, the availability of fairly accurate geologic and operational information makes possible a reasonable degree of standardization on mud treatment over a relatively large area. It may be said that, over most of this area where drilling is currently in progress, the natural mud made is very poor in quality, but responds readily to moderate chemical treatment to yield very good wall-building characteristics.

As far as field development drilling is concerned, the mud engineer's principal job, once the routine treatment best

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suited to conditions in a given field is determined, is to train the drilling personnel in the safe, effective, and economical handling of the mud conditioners required to provide adequate mud characteristics. For the most part, wildcat programs are essentially the same as average field programs, taking advantage, of course, of available information on the area from various sources. Here again, the problem is largely one of training crews, with a slightly greater possibility of meeting special mud problems as they arise.

It is the purpose of this paper to present a discussion of drilling-mud practices employed in the Southwest Texas area at present, both in connection with routine drilling, as well as methods of handling mud problems of a special nature which may arise from time to time. In addition, a discussion will be presented of developments in the application of slaked lime as a conditioning agent for drilling mud.

Discussion

Routine Mud Conditioning, Field Development

During the past several years, the routine mud treatment employed on wells drilled in the development of producing fields in the Southwest Texas area has become fairly well standardized from the standpoint of attaining ultimate mud characteristics favorable to drilling and completion operations. The chemical treatment employed involves primarily viscosity and filtration control. Formerly, the basic systems of chemical treatment have been about equally divided between the phosphate-bentonite treatment and the alkaline-tannate-bentonite treatment. However, the latter treatment has come into more general usage in recent years primarily because of an increase in the average well depth along with corresponding increases in weight requirements and mud temperatures. The alkaline-tannate muds are generally more stable at higher temperatures than those muds on which one or more of the polyphosphates are used as the primary dispersing agent. Also, the phosphate-treated muds depend entirely on dispersion of bentonitic material for filtration control, whereas the alkaline-tannate mixtures not only act as dispersing agents, but also provide additional colloidal material in the form of sodium tannate salts which aid the bentonites in lowering the filtration rate.

The following mud-conditioning program is employed at present with little variation in numerous fields in the area on wells whose depths generally do not exceed an average of 7000 ft. The chemical treatment is initiated at approximately 4000 ft and continued to the total depth. The average treatment varies from 10 to 45 days, depending on total depth and extent of coring, testing, and completion operations. The terminal filtration rates vary from 5 to 10 cc (API test); the mud weights vary from 9.8 to 13.3 lb per gallon; the terminal viscosity averages 45 sec (Marsh). The average routine employed for treating wells is as follows:

1. The mud weight schedule is calculated to provide from 400 to 500 psi overload above known formation pressures. The pressure information is obtained from subsurface pressure surveys on producing wells or from drill-stem test data on previously drilled wells. Mud weights above 10.0 lb per gallon usually require the addition of barytes for weighting material.

2. The viscosity of the mud is maintained at 40 to 45 sec. If the viscosity tends to remain above 45, the treatment outlined below for filtration control is supplemented by the addition of polyphosphates as necessary. Sodium hexametaphosphate or sodium tetraphosphate is used when the mud temperature at the flow line is 120°F or less; if above 120°, sodium acid pyrophosphate is more effective. A moderate and practically con-

tinuous stream of water should be added to the mud at all times, unless the viscosity tends to remain below 40 sec. The proper use of water will save on chemicals used for viscosity and filtration control.

icals will prolong their effectiveness and prevent excessive rise in viscosity due to abnormal clay concentration. The addition of bentonite and caustic soda-quebracho mixtures should be reduced when the filtration rate becomes less than 10.0 cc, and increased if it rises above that value. The pH of the mud resulting from the alkaline-tannate treatment will vary from 9.5 to 10.5, depending largely on the length of time the treatment is in effect. This pH value apparently is not critical, although it is desirable to maintain a pH not less than 9.0 for best results.

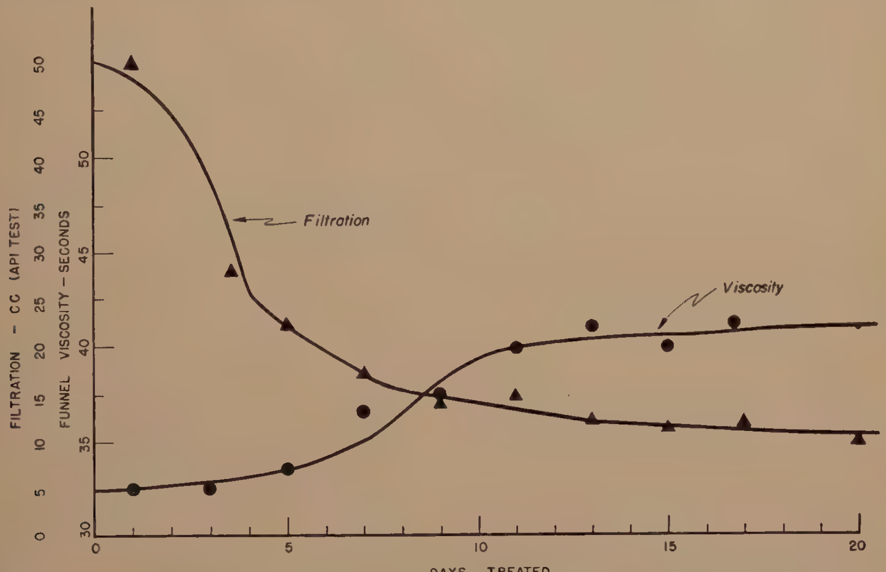

FIG 1—ALKALINE-TANNATE-BENTONITE TREATMENT FOR VISCOSITY AND FILTRATION CONTROL. AVERAGE WELL DEPTH, 6900 FT.

3. The desired filtration rate at completion depth is 10.0 cc or less. The initial filtration rate, before chemical treatment is begun, varies from 20 to 50 cc depending largely on the quality of the natural mud made in any given area. Throughout the area, the average treatment for filtration control is as follows, usually initiated at approximately 4000 ft:

(*a*) Add 25 to 50 lb caustic soda mixed with 50 to 100 lb quebracho per drilling tour.

(*b*) Add 2 to 5 sacks of bentonite per tour, mixed not faster than 15 min. per sack.

(*c*) The above treatment should be accompanied with vigorous and practically continuous use of mud guns to obtain adequate mixing of chemicals and dispersion of the bentonite. The addition of a moderate stream of water along with the chemicals will prolong their effectiveness and prevent excessive rise in viscosity due to abnormal clay concentration.

Fig 1 illustrates viscosity and filtration rates obtained with this treatment on a typical well.

Planning of Drilling-mud Programs for Wildcat Wells

The provision of adequate mud properties for wildcat wells may be expedited by a thorough analysis on the part of the mud engineer of all information available on the area in the immediate vicinity of the well. Such an analysis will enable

sensible recommendations to be made on the casing and drilling mud program. On the majority of wildcats, plentiful information of this nature may be assembled from a number of different sources: namely, contacts with authoritative geologic personnel, scouting reports on nearby wells already completed or abandoned, contacts with various operators or contractors who have drilled in the vicinity of the prospective wildcat. Particular effort should be made to obtain, in so far as is possible, accurate information as to the occurrence and extent of abnormal pressures, lost circulation, sloughing shale, or any other conditions which will affect the drilling mud and casing program to be employed on the well.

Usually the recommended chemical treatment follows much the same program as that for routine field wells. However, in some instances, provisions must be made for unusual conditions anticipated, such as contamination due to penetration of anhydrite strata, pretreatment with bridging materials to prevent lost circulation in unconsolidated surface formations, and so on. Where abnormal pressures are anticipated at relatively shallow depths, the chemical treatment for filtration control is usually initiated before or shortly after surface casing is set, so that desirable filtration rates may be established before extensive weighting of the mud becomes necessary. On the majority of wildcat wells, the predetermined schedule for mud weight may be revised as drilling progresses, taking into account the pressure information obtained on successive drill-stem tests, and maintaining at all times approximately 500 psi overload above known or estimated formation pressures.

On the whole, it has been found that reasonably accurate and reliable information can be obtained on nearly any area, which makes possible the planning of an adequate mud program for a wildcat well in that area. Such a program will reduce the percentage of wells abandoned because of unforeseen mud problems.

Recommended Treatment for Special Mud Problems

There have been instances in the past, and will be in the future, when mud problems arise which may not be foreseen in the routine mud program either for field development wells or for wildcats. These conditions generally require some special treatment, often very simple, but sometimes more complex.

Lost Circulation

Causes: Lost circulation, sometimes called "lost returns," may be the result of one or more of the following circumstances:

1. Penetration by the well bore of a porous formation having a subnormal pressure incapable of supporting the hydrostatic head of the mud column already established.

2. The bit and drill collar may become balled up, causing excessive fluid pressure against normal pressure formations, resulting in rupturing the bedding planes and loss of mud.

3. Because of unanticipated abnormal pressure or actual show of gas in the mud system, the mud weight may be increased to yield a hydrostatic head greater than shallower formations exposed below the surface casing will support.

4. Penetration by the well bore of an actual crevice or fissured formation.

Treatment: Correction of lost returns depends on the severity of the individual case; that is, whether partial or total loss of circulation.

1. Partial loss of circulation may be very gradual but persistent. This condition is often corrected by increasing the mud viscosity to approximately 50 sec and reducing the mud weight slightly, if well conditions permit. The addition of bridging or sealing agents such as chopped cello-

phane and cottonseed hulls may also be beneficial. It has been found that the combination of these materials, using two parts of cottonseed hulls to one part of cellophane, is often more successful than use of either one without the other.

2. Total loss of circulation involves the problem of preventing stuck drill pipe as well as regaining full circulation. Often it will be found that the fluid level in the annulus may be relatively close to the surface, and hole conditions previous to the loss of returns may warrant an attempt to regain circulation with the pipe several stands off bottom rather than up in the surface casing. However, if it is estimated that the fluid level has dropped below the surface casing seat, it is advisable to come up in the casing, attempting to fill the hole with as light weight mud as is feasible. In either case, the mud employed to attempt to regain circulation should weigh as little as is considered safe, should have a viscosity of 50 to 60 sec, and should contain a minimum of 2 lb per barrel of cellophane to 4 lb per barrel of cottonseed hulls. If it is impossible to establish full returns after several attempts with this type of mud, it may become necessary to try to seal the crevice or porous formation (assuming its location is reasonably definite) by plugging back or squeezing the open hole below the surface casing with 4 pct bentonite cement mixed with 1 to 2 lb of cellophane per sack, or using a quick-set gypsum-type cement with chopped cellophane.

3. It should be borne in mind that, in the event of either partial or total loss of circulation, any attempts at regaining circulation should be made at considerably reduced pump speeds to minimize the circulation pressure in the annulus as much as possible. When it is apparent that full returns have been established at reduced pump speeds, the circulation rate should be increased gradually, until normal pump speeds are attained without further loss of mud, before drilling operations are resumed.

4. When it is apparent that returns are lost to unconsolidated formations exposed below the surface casing due to a necessary increase in mud weight for deeper drilling, consideration should be given to the advisability and practicability of setting an intermediate casing string to protect those formations.

Blowouts

Causes: Blowouts, either gas, oil, or salt water, are the result of formation pressures exceeding the effective hydrostatic head of the drilling fluid, because of one or more of the following reasons:

1. Penetration of a formation having a pressure greater than the actual hydrostatic head of the mud column.

2. Reduction of the effective hydrostatic head of the mud column because of the swabbing effect of pulling a balled-up bit, thus allowing formations to produce into the well bore which normally would have been controlled by the mud weight used. It is estimated that this swabbing effect may lower the hydrostatic head by as much as 300 to 400 psi, particularly if the pipe is pulled when the mud viscosity is abnormally high. This is one of the commonest causes of blowouts.

3. Loss of mud to a low pressure formation sufficient to lower the normal effective height of the mud column enough to allow either normal or abnormal pressure formations to flow into the well bore.

4. Failure of mud to release entrained gas at the surface, due to excessive viscosity, thereby reducing the hydrostatic head.

Treatment: The prime requisite for correction of a blowout, regardless of the cause, is to bring the well under control as rapidly as possible. This may be accomplished in the following steps:

1. Close the well in with the blowout

preventer and divert the flow through a choke line.

2. Circulate the well on as large a choke as possible, yet still control the well flow. The rate of circulation should be such that the amount of returns is equal to the input, neither more nor less. Avoiding the use of too small a choke is a prime consideration here.

3. Weighting material should be added as rapidly as possible, often as fast as 5 to 10 sacks per minute, until the mud weight is increased enough to quiet the well and release the back pressure afforded by the choke.

4. In the event the mud weight required to kill the blowout is greater than shallower formations will support, it is often possible to quiet the well by placing a 1000 to 2000-ft plug of barytes weighing 20 to 24 lb per gallon.

5. The mud viscosity should be not greater than 42 sec, to facilitate release of gas from the returns. This may be accomplished by chemical treatment, moderate addition of water, and vigorous use of mud guns.

6. In many cases it is desirable to discard badly oil-cut mud in the returns, or mud badly contaminated with salt water, replacing it with clean, weighted mud as quickly as possible.

7. It should be pointed out that the success or failure in controlling a blowout depends largely on the condition of the blowout-preventer equipment, and the familiarity of the crews with its operation. The preventers should be tested at least daily with complete blowout drills by all crews. If hydraulically operated, they should be equipped with a standby water or oil pump which is used for that purpose only, rather than depending entirely on other rig pumps for that service. Choke lines or manifolds and their valves should be kept in good working order at all times, with a number of chokes ranging in size from ⅛ to 1⅛ in. readily available.

Sloughing Shale

Causes: Sloughing shale may occur in one of several ways. It may either be very gradual, resulting in an overall enlargement of the drilled hole, or it may be rapid enough to form shale bridges capable of sticking the drill pipe or interrupting circulation. In either case the factors contributing to the sloughing condition are as follows:

1. Hydration of shale formation by mud filtrate sufficient to loosen the shale and cause sloughing.

2. Amount of sloughing may be influenced by the angle of the bedding planes; the greater the angle, the greater the tendency of the shale to slough in quantities sufficient to cause bridging.

3. The presence of shale gas in the formation, limited in volume but under abnormal pressure, tends to aggravate the sloughing condition.

Treatment: The type and effectiveness of treatment for sloughing shale depends largely on the individual characteristics of the formation giving trouble. In many cases, reduction of the mud filtration rate to extremely low values will correct the sloughing condition by virtue of decreasing the amount of filtrate entering the formation, as well as altering the chemical content of the filtrate making it less likely to cause hydration of the shale. Filtration rates of 5.0 cc or less may be obtained by employing an alkaline-tannate-starch treatment, as follows:

1. If time and well conditions permit, it is advisable to treat with caustic soda and quebracho to raise the pH of the mud to approximately 12.0 before adding starch. This may be accomplished by adding the dry chemicals slowly in equal proportions through the mud hopper, with vigorous use of the mud guns, providing prohibitive viscosities do not result. In the latter case it may be necessary to add the chemicals in solutions of 50 lb caustic soda to 50 lb quebracho per barrel of

water, treating as rapidly as the mud will take the chemical without excessive rise in viscosity. In either case it may be necessary to accompany the chemical treatment with moderate addition of water to reduce the clay concentration of the mud sufficient to take the subsequent starch treatment. The purpose of the high pH treatment is to prevent fermentation of the starch.

2. In the event it is decided to use germicides rather than the high pH treatment to prevent fermentation, it is desirable to treat the mud with the chosen germicide to the proper concentration before adding starch. Few germicides are available which, although they prevent fermentation, do not adversely affect mud viscosity or cause excessive foaming.

3. After converting to high pH mud or treating with the germicide, pregelatinized starch should be added to the mud slowly through the hopper in approximately 2000-lb batches, with several hours' circulation between batches, until the filtration rate has been reduced to the desired value, usually less than 5.0 cc. The mud pits should be stirred continuously with the mud gun discharges below the surface to minimize foaming. Care should be taken to change the position of the mud guns periodically to avoid stagnant areas in the pit, thus giving the entire mud system the benefit of being subjected to the bottom hole temperature, which aids in preventing fermentation.

4. If steam is available, raw corn starch may be gelatinized on the job, utilizing an appropriate vat equipped with a live steam outlet to roll the mixture. The starch may be added in the proportion of 50 lb starch per barrel of water, mixed and rolled thoroughly with steam, then treated with about 10 pct caustic soda by weight of starch, and cooked until the mixture turns to a clear amber color. The solution may be added directly to the mud ditch. This treatment is less expensive than the use of pregelatinized starches. However, the latter may be used equally well with power or steam rigs without the necessity for special mixing equipment.

5. Addition of chemicals and starches for maintenance will depend largely on the drilling rate and the type of formations drilled. The daily amounts of additives used should depend entirely on frequent tests for filtration, pH, or germicide content.

6. In the event the low filtration starch mud fails to correct the sloughing condition, and the well justifies the additional expense, the mud system may be changed entirely, substituting a sodium silicate mud. This is a very expensive treatment, generally used only on wells of sufficient geologic merit to justify the expense. Inasmuch as this treatment has had limited application in this area, it will not be described herein.

Excessive Chloride Contamination

Cause and Effects: There have been several wildcat wells drilled in recent years on which salt-water sands were penetrated which apparently had formation pressures equalling or very slightly exceeding the hydrostatic pressure of the mud column, enough to cause a severe contamination of the mud system without resulting in a recognizable salt-water flow. This condition has resulted in the following changes in normal mud characteristics:

1. Erratic reduction in mud weight, usually resulting in variations in weight not exceeding 0.5 lb per gallon less than the normal uniform weight, and usually accompanied by a slight show of gas in spots.

2. Rapid and spasmodic increase in viscosity from normal to as high as 75 sec, with an eventual sharp reduction in viscosity provided corrective measures are not taken soon enough.

3. Marked increase in filtration rate from 10.0 cc or less to 60 cc or higher.

4. Chloride content of contaminated portions of the mud system has increased from approximately 1000 to as high as 17,000 ppm. If corrective measures are not taken very soon, the average chloride content of the entire system will continue to increase.

5. Returns from bottom after prolonged shut downs show most pronounced evidence of severe salt-water contamination and often a slight gas kick.

Treatment: If the above symptoms are recognized within a reasonable time after the contamination has started, the mud system may be renovated without the necessity of discarding any great amount of the contaminated mud. The resulting mud will have wall-building characteristics as good as, or better than, the original system. The following steps should be carried out as nearly simultaneously as is practical:

1. Addition of weighting material sufficient to increase the mud weight at least 1 lb per gallon or more over the original mud weight, watching carefully for any evidence of lost returns.

2. Rapid addition of caustic soda-quebracho mixtures to increase pH to approximately 12.0.

3. Addition of pregelatinized starch to reduce the filtration rate to 5.0 cc or less.

The above treatment has been carried out successfully on a number of jobs resulting in alkaline-tannate-starch muds weighing from 13.5 to 14.5 lb per gallon, with normal, easily maintained viscosity. The average chloride content of these systems has ranged from 6000 to 9000 ppm. It is believed that the reasonably high chloride content has been beneficial in preventing excessive clay concentration which would result in unmanageable viscosities.

Mild cases of salt water contamination resulting in increased chloride content up to 3000 to 4000 ppm may be arrested by increasing the mud weight and slight intensification of the alkaline-tannate treatment.

Sulphate Contamination

Cause and Effects: Sulphate contamination of mud may arise from having drilled formations bearing gypsum or anhydrite, or from the use of make-up water containing appreciable amounts of soluble sulphates. The symptoms of severe sulphate contamination are outlined as follows:

1. The viscosity of the mud increases sharply initially, followed by a rapid decrease. The mud generally has a very flocculated appearance both during the high viscosity stage as well as afterward.

2. The mud filtration rate increases rapidly in much the same manner as indicated in excessive chloride contamination. An ammonium oxalate test of the filtrate will yield a white precipitate indicating the presence of calcium sulphate.

3. The pH of the mud generally will drop sharply in cases of severe contamination. The amount of alkaline-tannate solution required to maintain high pH mud is much in excess of normal requirements.

Treatment: Sulphate contaminated mud has been treated in the past, with rather mediocre success, using soda ash (sodium carbonate) in combination with caustic soda-quebracho mixtures. This treatment usually restored normal pH values, but often resulted in excessive gel rates and gel strength in the mud, attributed largely to accumulation of excess sodium ion in the system. During recent years, mud systems badly contaminated with sulphates from anhydrite drilling and systems which employed make-up water which contained about 1300 ppm sulphate have been treated successfully using barium carbonate. On those wells where anhydrite was drilled, the mud employed was an alkaline-tannate-bentonite system having a filtration rate of 5 to 10 cc and a pH of 10.0 to 10.5. The treatment for sulphate contamination is outlined below:

1. If the penetration of anhydrite can be anticipated, the average mud system should be pretreated with approximately 2 lb of barium carbonate per barrel of mud mixed slowly through the hopper, in addition to the normal alkaline-tannate-bentonite treatment.

2. If the mud returns, after penetrating the anhydrite strata, show evidence of flocculation, or the mud filtrates show a positive test for sulphates, additional barium carbonate should be added until the flocculation disappears and the filtrates indicate no soluble sulphates in the system. This treatment should be repeated as often as indicated on the tests. Generally, 200 to 300 lb of barium carbonate per day is sufficient to prevent further contamination during the time the anhydrite section is being drilled.

3. In numerous cases, although the barium carbonate prevents or corrects excessive flocculation, the filtration rate of the mud will not approach its former low value. If filtration rates less than approximately 12.0 cc are necessary, the alkaline-tannate-starch treatment should be used. The barium carbonate treatment will in no way interfere with maintenance of the starch mud, but will benefit the pH control.

4. The presence of appreciable amounts of phosphates in the mud will inhibit the reaction of barium carbonate. Phosphate treatment for viscosity control should be discontinued at least 24 hr before addition of barium carbonate. Generally, the use of 25–50 caustic soda-quebracho mixtures and moderate addition of water is sufficient for adequate viscosity control.

5. On wells where the make-up water contains relatively high concentration of soluble sulphates, an initial treatment of 2000 lb of barium carbonate generally is sufficient to correct the flocculation of the mud shortly after drilling the plug in the surface casing. Small amounts of barium carbonate may be added periodically, as indicated on tests of the mud filtrate. Approximately 300 lb per week usually will suffice. The filtration rate of the mud may be maintained at 7.0 to 10.0 cc with a moderate alkaline-tannate-bentonite treatment.

Cement Contamination

Effects: The drilling of relatively green cement will generally cause several detrimental effects to the properties of the average drilling mud, such as the following:

1. Severe flocculation resulting in excessive initial viscosity followed by a sharp drop in viscosity after 24 to 36 hr. This latter reaction is caused by precipitation of clays and colloidal material.

2. Abnormal rise in mud filtration rate, often approaching 100 cc.

3. Appreciable rise in pH, often increasing from 8.0 to as high as 13.0.

Treatment: The above detrimental effects of cement contamination can often be prevented or definitely modified by pretreating the mud with dry quebracho mixed slowly through the hopper, agitating the mud in the pit vigorously, and allowing this mud to reach the bit before drilling is begun. The average mud system requires 300 to 500 lb of quebracho to prevent contamination from 40 to 50 ft of cement drilled. This treatment may be supplemented by moderate additions of phosphate if needed for viscosity control. The treatment is most effective for mud weighing less than 12.0 lb per gallon, though it will definitely benefit the higher weight mud. Dry quebracho mixed through the hopper will effectively reduce the viscosity of cement contaminated mud that was not pretreated. However, it is usually necessary later to add clays and chemicals to restore lost colloidal material.

Lime Treatment

Background and Development

For approximately 25 years, lime has been added to drilling mud in small quan-

tities to obtain a temporary large increase in viscosity as an aid to successful penetration of unconsolidated surface sand and gravel formations. This treatment depended primarily on the rather severe initial flocculation of bentonite constituents of the mud on contact with lime. Similar results may be obtained using portland cement as the flocculating agent, and this medium has been used frequently in lieu of lime.

A somewhat later development in the mud treating art is the application of slaked lime, paradoxically, to prevent excessive rise in viscosity and gel strength of drilling fluids. In one sense, this treatment may be considered a controlled flocculation or precipitation process which prevents the overaccumulation of those clays that may become hydrate which normally tend to produce erratic increases in viscosity and gel strength. The use of conventional dispersing agents as a means of successfully controlling these erratic properties is normally rather short lived in that beyond a certain clay concentration, or total solids concentration, the chemicals lose their effectiveness, necessitating the addition of large amounts of water to reduce the clay concentration. It may be seen readily that this type of treatment leads to considerable expense, particularly on muds on which weighting materials are required to maintain the desired density. The lime treatment offers a means of avoiding the necessity of repeated watering to reduce the solid content and subsequent addition of weighting material. Also, it results in considerable reduction in the amount of chemicals needed for routine viscosity control. A secondary, but very important consideration, is that these savings may be accomplished by use of a chemical costing approximately 1⅓¢ a pound, compared to 5 to 20¢ a pound for other mud treating agents.

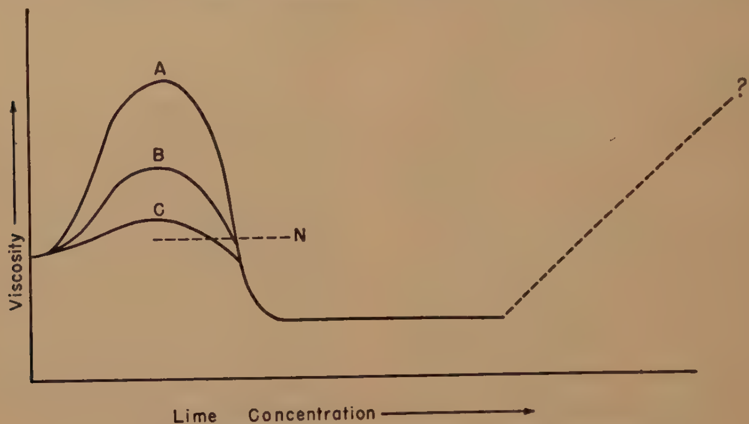

FIG 2—VISCOSITY BEHAVIOR ON ADDITION OF LIME TO DRILLING MUD.

No attempt will be made at this time to present a detailed theoretical analysis of the chemistry involved in the lime treatment. There have been several published theories on this subject that are not in strict agreement as to the definite chemical reactions taking place. It may be stated with reasonable assurance, however, that the net result of the addition of lime to drilling mud is a reduction in the amount of water of hydration of the clay particles as well as a reduction in their tendency to cling together forming a strong gel. Both results are reflected in the viscosity and gel strength behavior of successfully handled lime mud.

Fig 2 presents a schematic diagram of the typical reaction of drilling mud upon

initiation of the lime treatment. The curves indicated represent viscosity plotted against increasing lime concentration. No attempt is made to assign definite numerical values either for viscosity or lime concentration because those values for a given mud depend on several variables, such as total solids content, bentonite concentration, concentration and nature of other chemicals used previous to the addition of lime, and even the density of the mud at the time the lime treatment is begun. The magnitude of the viscosity peak on the curve depends primarily on these variables. *A* represents a mud having a high total solids and bentonite content, as well as having been treated previous to the lime conversion with considerable phosphate. *B* may represent a mud with a moderate total solid and bentonite content, but probably very little previous chemical treatment with no phosphates having been added. *C* indicates the typical reaction of a mud with a low total solid content and practically no bentonite. From an operational standpoint, this is the most desirable situation for conversion to lime mud in that normal drilling operations are less likely to be interrupted because of extreme viscosity occasioned by the conversion. It will be noted that on all three types of mud, after sufficient lime has been added, the viscosity falls considerably below its initial value and remains low for a somewhat greater lime concentration. The dotted portion of the curve represents a possible increase in viscosity on addition of very excessive amounts of lime. In the authors' experience, this reaction has not been demonstrated by adding excess lime. However, it has been indicated on several wells where lime-treated mud was used and large amounts of cement were drilled, the first reaction being a reduction in viscosity to a low value, remaining at that value for some time, then increasing rather sharply.

A successfully treated lime mud is one that the amount of lime added for daily maintenance is sufficient to maintain normal viscosity at a point on the curve to the right of the conversion peak, as shown by *N*. Generally speaking, this concentration of lime must be arrived at by trial and error methods on a given mud system. Experience in the past has shown that, for the average mud system, the amount of lime for daily maintenance may vary from 50 to 300 lb or more for different areas, depending on the type of formations penetrated, rate of penetration, size of hole drilled, and amount of sacked bentonite needed for filtration control.

Recommended Procedure

Since one of the more difficult problems associated with the use of lime mud involves the maintenance of proper lime concentration, attempts to solve this problem include the addition of lime and bentonite in a definite ratio in conjunction with alkaline-tannate mixtures. This method of adding lime has produced good results on a number of wells; however, on those wells where quebracho-caustic soda additions have greatly exceeded that of lime, very dubious results have been obtained. This may indicate that a second relationship exists between the alkaline-tannate and the lime concentration in the mud.

The treatment outlined below has been successful on a number of recent wells. It is initiated generally at 4000 to 5000 ft, shortly after the ditches and pits have been cleaned of sand accumulated during the drilling of surface hole. It is important to mention that this procedure may be used successfully only when the total solid and bentonitic content of the natural mud is very low. The treatment is based on a bentonite-lime ratio of approximately 4 to 1, and a lime-caustic soda-quebracho ratio of 1-1-1. The treating procedure is as follows:

1. Add 30 to 40 sacks of bentonite as rapidly as is practicable.

2. Add simultaneously with the bentonite 1500 to 2000 lb each of lime, caustic soda, and quebracho. The average concentration of these chemicals is 1½ to 2½ lb per barrel of mud in the system.

3. Continue to add 2 to 4 sacks of bentonite and 100 lb each of lime, caustic soda, and quebracho per tour (8 hr) until the filtration rate is reduced to 10 cc or less.

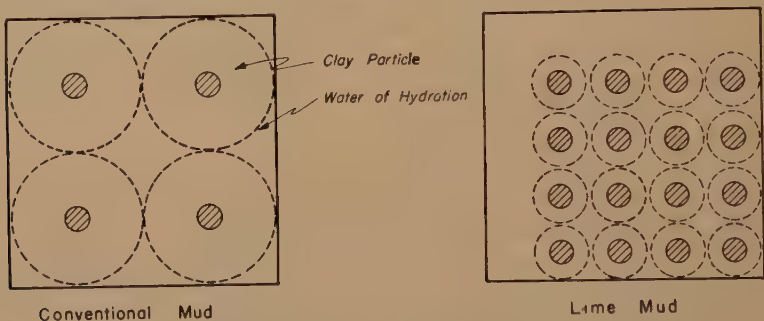

Fig 3—Water of hydration of clays and its relation to mud density.

4. Continue adding the same quantity of chemicals as long as the drilling rate is reasonably fast, and add bentonite only as needed to maintain the filtration rate at the desired value. On reduction of the drilling rate, the amount of chemicals may be reduced to 50 lb per tour or less.

5. A moderate stream of water is added to the mud as long as the funnel viscosity exceeds 38 sec. During the initial phase of the treatment, the viscosity may be reduced excessively, and it may be necessary to leave the water out until the viscosity increases to a favorable value.

A slight variation in the initial phase of this treatment is necessary on muds having a high total solid or bentonite content. To avoid unmanageable viscosities, the mud may be treated rapidly with the caustic soda-quebracho mixtures to obtain low viscosity, followed by addition of 1½ to 2½ lb per barrel of lime. After the viscosity peak has passed, and the "break over" has been obtained, the bentonite may be added to avoid unusually low viscosity. Thereafter, steps 3 to 5 above may be followed.

Types of Wells Where Lime Mud May or May Not Be Used

In general, it has been found that lime-treated mud is applicable to three groups of wells:

1. The deeper wells where drilling consumes at least 30 days, and where mud temperatures may be expected to be high. The use of lime mud on this type of well eliminates the use of phosphates required at greater depths for supplementary viscosity control. The higher temperatures render the phosphate treatment less stable.

2. Wells on which it is necessary to maintain a mud weighing from 10.6 to 11.2 lb per gallon for a period of time exceeding 3 or 4 days. It has been observed that with the use of lime a heavier mud may be expected without adding barytes. With conventional treatments, it has been normal for the mud to weigh about 10.3 lb per gallon prior to adding weighting material, whereas with lime mud natural weights as high as 11.2 lb per gallon are readily obtained. The attainment of this depends largely on the manner of treatment; avoiding extreme viscosity peaks necessitating the addition of large amounts of water at any one time results in higher average density. It is thought that the higher density of lime-treated mud is a

direct result of reduction in the water of hydration of bentonites, allowing a greater accumulation of these relatively smaller particles, hence greater density per unit volume without excessive viscosity. Fig 3 illustrates this concept.

2. Wells where the natural increase in density of lime mud is undesirable because of the tendency for lost circulation. On this class of wells it is often desirable to maintain mud weights averaging 9.8 lb per gallon or less; consequently, the use of lime mud results in the need for excessive watering and addition of bentonite to keep the mud weight down.

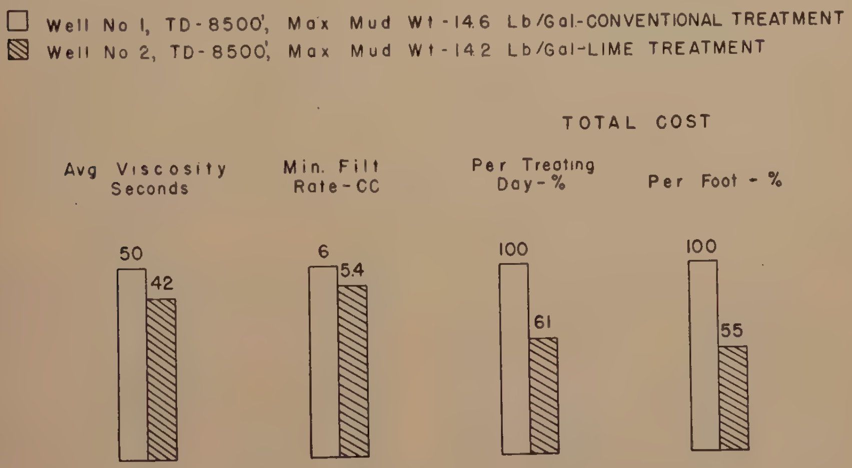

FIG 4—ECONOMICS OF LIME TREATMENT.

3. The third group of wells where the lime treatment is applicable are those where starch is to be used to obtain extremely low filtrations. The use of lime reduces the amount of caustic soda needed to maintain high pH, as well as prevents overaccumulation of natural clays which normally results in high viscosity. The amount of starch needed to maintain low filtration rates is also much less with the lime treatment.

Converse to the above, there are two types of wells where the use of the lime treatment may be undesirable:

1. Wells where the drilling time is of relatively short duration, usually less than 30 days. On this group of wells the use of lime generally results in insufficient reduction in filtration rates by the time the completion depth is attained. The rate of reduction in filtration rate of the alkaline-tannate-lime-bentonite system is generally somewhat slower than with conventional treatment.

Economics of Lime-treated Mud

As mentioned at the outset of this discussion, a prime consideration of the lime treatment is the possibility of establishing and maintaining desirable mud characteristics at a saving in cost over conventional treatments.

Fig 4 presents a comparison of two wells drilled to comparable depths by the same rig, using the conventional mud treatment on the first well and lime-treated mud on the second. Both wells had total depths of 8500 ft, with a maximum mud weight of 14.6 lb per gallon on the well using the conventional treatment, and a maximum weight of 14.2 lb per gallon on the lime-treated well. The comparative viscosity and filtration characteristics are shown, with a slight advantage in favor of the lime treatment. The total cost per day

WELLS USING CONVENTIONAL TREATMENT (5 Wells)					
				AVERAGE TOTAL COST	
Average Depth		Max Mud Weight		Chemicals	Weight Material
6634		10.6		$777	$ 747
Average	Cost	Per	Day	$ 28.78	$ 27.67
Average	Cost	Per	Foot	$ 0.12	$ 0.11

WELLS USING LIME TREATMENT (3 Wells)					
				AVERAGE TOTAL COST	
Average Depth		Max. Mud Weight		Chemicals	Weight Material
6661		10.6		$485	$103
Average	Cost	Per	Day	$ 26.94	$ 5.72
Average	Cost	Per	Foot	$ 0.07	$ 0.02

FIG 5—COSTS OF WEIGHTING MATERIAL.

WELLS USING CONVENTIONAL TREATMENT (8 Wells)			
Average Depth	Average Days	Average Cost/Day	Average Cost/Foot
7625	46	$40.03	$0.217

WELLS USING LIME TREATMENT (2 Wells)			
Average Depth	Average Days	Average Cost/Day	Average Cost/Foot
7731	60	$14.08[a]	$0.118[b]

a	65 Percent	Reduction
b	46 Percent	Reduction

FIG 6—COSTS OF CHEMICALS.

and per foot are plotted as 100 pct for the conventional treatment, compared to 61 pct per day and 55 pct per foot for the lime treatment. This represents a 45 pct reduction in cost per foot for the lime-treated mud. Comparison of the treating costs on a number of similar wells in the area reflects similar savings in favor of the lime treatment.

Fig 5 indicates the savings that may be expected by virtue of a higher natural mud weight attained with the lime mud. It may be seen that a saving of about $22 per day was realized on weighting material with a mud weight of 10.6 lb per gallon. This is only 0.3 lb per gallon in excess of the average natural mud weight of conventionally treated mud. If the required weight had been on the order of 11.0 lb per gallon, the economic advantage of the lime mud would have been proportionally greater.

Fig 6 presents costs of chemicals required for mud conditioning on 8 wells using the conventional treatment, as compared to 2 wells using lime mud. A reduction in chemical costs in favor of lime mud of 65 pct per day and 46 pct per foot is noted. A large part of this cost reduction may be attributed to the use of lime mud; however, closer supervision of mud treating on the latter two wells was a factor in reducing the quantity of mud conditioners required. It will be noted also that the difference in chemical costs on these wells is considerably greater than that indicated in Fig 6. This may be attributed primarily to the difference in total depths: the 6600-ft wells required a comparatively light conventional chemical treatment compared to the 7700-ft wells. This is partially a function of the difference in mud weight requirements, as well as difference in mud temperatures.

Conclusions

It may be stated in conclusion that the mud-treating techniques described herein have been adequate in the past in providing favorable characteristics for drilling and completing both wildcat and routine field wells in Southwest Texas. Over the past several years, mud-treating costs in general have shown a rather marked increase due primarily to increasing average well depth. The largest item of mud expense on the deeper wells is weighting material, which constitutes approximately 65 pct of the total mud bill. Future developments in mud conditioning technique which will either arrest these rising costs or lower them will be welcomed by the industry.

The information presented on lime mud treatment was gathered during the relatively early stages of its development. It holds considerable promise in the all important struggle to keep drilling-mud costs as low as possible consistent with good drilling practice. Since the treatment has been in use, concepts of how and why it works have changed rapidly and the problem has yet to be solved definitely. Progress is being made on that score by both research and operating personnel. At this writing, the field application of the lime treatment has become rather widespread throughout the Southwest Texas area and will become more so as procedures are perfected and greater savings are realized.

CHAPTER VI. *Petroleum Engineering Education*

A Viewpoint on Petroleum Engineering Education

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ABSTRACT

EDUCATION is for the purpose of developing citizenship, and, if it is pursued for the additional purpose of preparing for a professional career, such as engineering, it is also directed to developing a knowledge of essential science, aptitude for the application of science to practical situations, and a knowledge of the industrial art in which the engineer will be engaged. The process of education required for engineering must of necessity extend beyond the classroom into industry. For that reason, the education of engineers should be divided as between the university and industry. Specialization in engineering should logically come as a result of experience in an industry. The student cannot take the time in a university, and, the university cannot teach the skills required to develop a specialist without sacrifice to the more essential broad purposes of formal education.

In addition to talent in science, aptitude in the application of scientific fact, and knowledge of the industrial art, the engineer should possess certain personal qualities which are helpful in the pursuit of a professional career. Those personal qualities are: the ability to work as a partner in an enterprise, the ability to do jobs in a way whereby job performance is a means of gaining experience and increased responsibility, the capacity to write and speak in an understandable manner, and, a proper regard for the "significance of answers." These personal qualities may be of almost equal importance to acabemic accomplishments in the field of science. Development of such personal qualities are an essential part of the student's training in the university and in industry. They can be developed effectively through the leadership of instructors.

COMPULSORY EDUCATION

Nature played a mean trick on the human race when the evolutionary process failed to develop in the individual a capacity to inherit knowledge. Were knowledge transmissible in a cumulative manner from generation to generation, mankind would be by inheritance wise beyond measure within a few generations. Then there would be little if any need for a "system of education." As matters stand, however, all must suffer the burden of starting life at the "zero" level of learning from which station each rises depending upon individual capacity to assimilate knowledge left of record by our predecessors and the individual effort exerted to compensate for Nature's failure to endow the offspring with intelligence.

In the United States some degree of education is generally regarded as essential and necessary. Therefore, all citizens are subjected by law to an educational process covering the primary school age from six to sixteen years. Beyond the schooling required by law, many attend secondary schools, and beyond that, schools of higher learning. Our standard of living is at a level that permits an increasingly large fraction of the population the opportunity to go through all of the formal educational process. As a result, education in the colleges and universities has almost reached a mass production level. In spite of the high

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output, the demand for "Engineers" and other professionally trained graduates exceeds the supply.

One of the requisites for recognition in the practice of engineering in the professional field is possession of a college degree. Such a degree at least certifies that the engineer was once a student and demonstrated some capacity and aptitude in the field of engineering. This discussion is directed to the educational process that produces run-of-the-mill graduates in engineering. The discussion assumes that the average engineering student submits to the formal educational process in order to practice engineering as a means of attaining in some measure a life of comfort, contentment and security; and, of satisfying an urge to extend the field of human knowledge in the practical arts for the benefit of present and future generations.

Major and Minor Subjects

The library left by preceding generations has grown to such volume and complexity that students can take time in school to study only part of the knowledge recorded. For that reason, students specialize. Specialization confines the student not only to certain fields of knowledge, such as engineering, but also attempts to permit the serious study of limited subjects within the chosen field. One of the problems of the average student is that of picking a "major" subject supported by the proper collection of "minors." One such major-subject is Petroleum Engineering.

There is a conflict of ideas in respect to the design of the educational process, particularly as it applies to course content in the university. In some universities there is a major-minor classification of studies. Among the major subjects are found many courses of instruction bearing titles related to training in the industrial art. These crowd out so-called minor subjects which are often "survey" courses to accomplish a degree of orientation of the student in either the science or the world to be encountered in his professional activity.

Does the major-minor classification short circuit training in fundamental science at a time in the student's life when he most readily acquires training in theory? Is the effort to introduce professional training through the field of major subjects an attempt to produce a professional engineer on the day of graduation? Insofar as the conflict of ideas may exist between those responsible for the teaching function and those in industry, few take the extreme view that specialization should be eliminated from the curriculum in the schools of higher learning in order to make every student, first, a "citizen" of the universe. Rather, criticism of specialization in engineering on the part of industry is more often directed to the tendency to lead the student away from the opportunity to learn all that he may be capable of learning in those fields of knowledge which are distinctly the fundamental basis for the practice of engineering and which are distinctly within the province of the schools of higher education.

This latter point of view is supported by thought that specialization in engineering is something to be developed in the practice of engineering itself. It must come from practice in the practical arts and must of necessity, therefore, be developed in industry. The argument against specialization in the professional schools may be supported further by observing that students are usually at an immature stage where none can know how far time and circumstance might carry them were they to take the opportunity to learn more about the minor-subjects that were neglected in favor of the so-called major-subject.

The idea that students do not have to bother about learning some things not directly related to the major-subject is basically wrong because it assumes the student's life work will be limited to the narrow groove represented by a chosen

specialty. It also assumes the groove will remain at the same dimension without influence from research and discovery. Whatever can be learned should be learned. Any knowledge acquired is useful knowledge.

Engineering

John Mills[1] has defined activity in American industry in the following way: "What can be done physically is the question for science; how to do it economically and usually on a large scale is that of engineering; but whether to do it at all, and if so, for whose advantage, is the executive question."

The engineer is the link between science and management. He must have sufficient knowledge of the basic science to understand what it is that has been proved possible. He must have a cultivated capacity to apply the scientific fact to practical situations. A sufficient knowledge of science is the basic tool of the engineer's trade, while acquaintance with the industry in which he is employed is essential to the intelligent use of his tools. Therefore, the process of educating a successful engineer must involve two major phases: (1) the cultivation of intellect and the acquisition of scientific knowledge, and (2) education in the industrial art wherein the engineer is to practice his engineering talents.

Specialization in the university may improperly weigh the fact that education in engineering must continue beyond the academic stage. Education starts from a zero level and is a process that continues over most of a lifetime. It does not end on graduation day.

Objectivity in Engineering Education

Opinions expressed indicate that industry strongly urges the formal educational process in the university be confined solely to the first phase while industry undertakes the second. The universities are told by industry to omit the so-called "applied courses."

The further reason may be given that the university is not a trade school. It could hardly teach a man how to drill a well, how to be a good roustabout, or how to become a successful supervisor. These are skills which can be learned only through practice in doing. In the final analysis it would appear that one would not go to the university in the first place if his objective were to become a craftsman. There is little need to confuse the proper segregation of the educational process on the theory that an engineer cannot practice his profession unless he has perfected manual skills in the operations which his scientific knowledge is called upon to improve. Many men own or direct highly successful oil production enterprises who have never drilled a well or who have never served as a roustabout. In like manner, the oil industry has enjoyed great technical advances as a result of the application of engineering principles on the part of engineers who themselves would be poor mechanics if called upon to function as skilled laborers in the process they themselves have designed.

One of the most difficult situations presented to an employer is that of an applicant graduate engineer who "took" petroleum engineering because he did not know what else to do, or because somebody convinced him that it was a fruitful field of endeavor for which he was particularly suited, or because he wanted to get away from the city life and into the wide open spaces, or because some friend of the family thought that the petroleum industry was important and should offer some opportunities.

The reasons for graduating in engineering cover every urge from the romance of being a builder to the desire to acquire great wealth. A lack of understanding objectivity is evident on the part of too many graduate engineers, particularly on the

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[1] References are at the end of the paper.

part of petroleum engineers. The real practice of engineering is far removed from the usual experience of a young man who might have been led to study engineering because of certain demonstrations of natural inclination toward mechanics or other supposed aptitudes indicative of future proficiency in engineering. It may well be asked if a student at the age of immaturity represented by his college years is capable of an intelligent choice of a "specialty." One of the remedies suggested lies in the thought that students should not be trained for some presumably specialized field of engineering. Rather, the universities should train engineers to take a position in any industry, or at least in any one of a group of related industries. If this were done, then clearer recognition would be given to the fact that the educational process is to extend beyond the classroom and is to continue in industry.

"Applied" Course Content

Why should engineering students elect to study petroleum engineering? This question cannot be fully discussed as a part of a general discussion. It is fundamentally involved, however, in the issue of specialization. In examining one proposed curriculum in petroleum engineering it would appear that a student would elect to take that specialty in order to spend twenty semester hours of his college career taking courses with the following titles: oil field mapping practice; oil field development; oil and gas production methods; oil and gas testing; petroleum accounting; economic geology of oil and gas; advanced oil field development problems; analysis of financial statements; principles of engineering investment and economy, after having had instruction in the basic courses titled: engineering drawing; general, qualitative, organic and physical chemistry; elements of economics; field geology, and general geology.

From an industrial viewpoint, there is reason to inquire about the value of consuming a total of twenty semester hours in such instruction. Certainly, engineering drawing, a course in surveying and a course in general geology should be sufficient to develop an aptitude for ready understanding of oil-field mapping practice. There is little that remains to be taught in oil and gas testing after a generous amount of instruction in chemistry. If such "applied" courses are given for the purpose of teaching nomenclature, identifying pieces of equipment, instruction in the habits of the industry, or for the purpose of equipping a student to the point where he may step from the classroom into industry and perform as a professional engineer, then many would conclude that the time is wasted.

Some justify the twenty semester hours or more of applied courses on the theory that the professional schools must supplement the courses taught in the "service departments" of the university as a means of teaching students by repetition. This indicates a weakness in the system of education that should not be hidden by resort to "applied course" titles. Others justify the so-called applied courses on the theory that some effort must be exerted to demonstrate to the student what part of the basic science courses can be applied in industry and what type of problems are to be met by the engineer. This reason is founded on the frank admission that the applied courses in reality are for the purpose of vocational guidance. Does it require twenty semester hours of college credit to render vocational guidance? If it takes that much or more, the student as well as the curriculum should be examined. The system may be at fault in trying to "make" an engineer out of unsuitable material. Is the graduate being primed with just enough industrial jargon to pass the employment interview only to fail when his short supply of engineering knowledge is consumed? One can succeed as a specialist in engineering only by being an engineer in the first place.

Vocational Guidance

In my opinion, such vocational guidance that may be necessary is not represented by any fixed number of hours of instruction in applied courses. The element of vocational guidance exists in the instructor-student relationship beginning at the time the student enters the university if it does not already exist in the secondary school. Instructors guide the destiny of students and certainly no course in a university is taken or given without presentation of some evidence as a part of the instruction of the use to which that particular field or element of knowledge can be put. In my opinion, the only purpose a student could have in becoming identified with a Department of Petroleum Engineering would be to attempt to establish a close relationship with instructors who are themselves recognized as petroleum engineers and who possess knowledge of the petroleum industry to the point where, through them, the student may develop viewpoints and understanding of what lies beyond the day of graduation.

The type of vocational guidance a student needs comes more from association with men than it does from a course of instruction yielding college credits. To fulfill this obligation the instructor must be in a position to teach what the industry is doing today and what its present problems are. There is little need to give the student exercises in what the industry did ten years ago. We are all familiar with the engineer who offers the "text book" solution to problems. Engineering is not imitation. Rather, it is the exercise of intelligent judgment based upon scientific fact. If there must be vocational guidance to help the student find his place in a chosen industry, the instruction involved should be a forward looking analysis of existing problems rather than a rehearsal of things done in the past.

One aid in bringing objectivity and understanding of an industry to the immature student would be summer employment. The benefit of summer employment would be great if the student were in a position to work more for the opportunity to learn than for the necessity of acquiring enough money to carry on the following year's schooling.

Essential Character in Engineers

In expressing a viewpoint on petroleum engineering education from the standpoint of industry, some attention must be directed toward the problem an engineer faces in successfully becoming a part of an industrial organization. A great deal has been said in public in recent years by responsible representatives of management concerning what it is that industry expects of engineers. The fact that management is beginning to speak out in this respect indicates, among other things, that executives are coming more and more to rely upon and to use engineering talent. The opinions expressed indicate that something in addition to sound basic knowledge of science and the ability to apply science to practical situations is required of the graduate engineer. For example, the Compton Committee of the Engineer Joint Council on the Economic Status of Engineers[2] in a preliminary report concludes that a quality of "personality" is of equal if not more importance than "scholastic record" or "indicated promise of development in specific field of engineering." Without the benefit of detailed information in respect to the questionnaire, one might speculate on those attributes of an engineer referred to as "personality" in the Compton Survey which industry considers of nearly equal importance to educational achievement. What is almost obviously involved in this respect arises from the circumstances that the apprentice faces in adjusting himself to the structure of an industrial organization.

Partnership Effort

The educational process from the primary school through the school of higher

learning should be dedicated to the principle of developing citizenship in its social, political and ethical senses. There is also citizenship of industry. The main requirement of that citizenship is having to work almost constantly and entirely as a partner in any enterprise. History gives to certain individuals sole credit for certain achievements. There are the Edisons, the Fords, the Marconis—individuals in achievement. Whether the historical record is correct in this respect is not important in the face of the fact that present-day activity is of such character that individuals can be recognized only to the extent that one may be an effective partner in joint effort. Industry, politics, civic endeavor, and any other activity is carried forward by "committee" effort. Few, if any, worthwhile engineering achievements remain to be the handiwork of any one individual. It is difficult for scientists and engineers in some instances to adapt themselves to such a circumstance. They are by nature individualists and often deeply worship individual recognition. The educational process must teach that individual recognition arises out of the leadership demonstrated and developed by a consistent contribution to partnership effort.

Job Integrity

One may further observe that the partnership nature of industrial enterprise requires that individuals employed be assigned "jobs" to perform. Apprentice engineers enter industry through the job-doing procedure. Jobs can be done in two ways. One way is to do the task assigned and sit back until another is given. In that way job routine develops. The apprentice finds himself fixed in a repetitive routine. Anybody can learn to do a job if it is a repetitive routine. A second way to do a job is to be aware of the fact that the job to be done is a part of a larger enterprise. With that in mind, the job presents an opportunity to learn about other related jobs that have to be done, and, about the larger task of which the assigned job is a part. Furthermore, any job is susceptible to improvement and to increase in efficiency so that the opportunity always exists in doing a job to demonstrate capacity for improvement in the routine. In the execution of job assignments there is involved an element of aggressiveness which is a test of one's ability to demonstrate capacity to learn as well as to demonstrate engineering aptitude. Jobs must be done in an efficient manner and every opportunity to learn must be taken if there is to be progression in responsibility and achievement in engineering. A job is an opportunity. The ability that an engineer demonstrates in doing jobs and his capacity for accomplishing jobs in an efficient manner is the measure of merit for advancement. The failure to progress in job responsibility is more often than not the fault of the individual.

Communicating Engineering Conclusions

Perhaps no element of engineering education has received greater critical attention from industry than that concerning the ability of engineers to communicate ideas and conclusions to others. The ability to write and to speak effectively is a personal quality of great importance. Of what use would it be to employ an otherwise competent engineer who could not make himself understood? Here is a real problem in education. The student engineer struggling through English I can never quite appreciate the problem to be encountered beyond the day of graduation when the wolves of industry will howl in disgust at his inability to tell what he knows. The difficulty may be with English I.

The following paragraph taken from the report of an apprentice engineer summarizing his experience in completing a training program assignment illustrates the type of English composition often encountered:

Careful planning and perhaps a smile from ubiquitous Dame Fortune enabled the writer to gain experience which is especially valuable due to the integrated diversity of the program. The progressive-minded nature of the District organization, together with a fine spirit of cooperation made possible instant transfer of attention to unique problems. In this way items of unusual interest received priority and routine tasks were allocated their proper attention, but due to absence of lost motion or inefficiency, every phase was brought under scrutiny.

The difficulty may be that every report and oral discussion in the college of engineering is not regarded as a means of instruction in the art of intelligent and effective communication.

Teaching engineers how to speak and write clearly is a problem of both the university and industry, but it is an educational function that rests primarily with the faculty of the professional school.

In my opinion, one of the greatest text books for the education of engineers is the volume comprising *Technical Writing* by T. A. Rickard.[8] The author of that text deserves great honor for having given not only instructions in the proper use of language but also advice on one's responsibility as an engineer. Rickard calls attention to the fact that an engineer is employed for the purpose of laying the basis for management decision. He is expected to arrive at conclusions and recommendations and to derive them from facts and analyses that can be clearly stated and confirmed. Such words or phrases as: about, very nearly, almost, approximately, the right order of magnitude, and others reflecting uncertainty in the engineering conclusion create doubt in the minds of those who must exercise the management decisions based upon the engineer's recommendations. Many engineers write or speak in a manner that suggests hedging for the purpose of escaping responsibility. That is the best way to destroy confidence and respect. If the conclusion reached cannot be described simply as black or as white, but is uncertain and takes on the quality of grayness, then the test of a competent engineer is his ability to come to the point and establish the several courses for executive action.

Rickard admonishes the engineer "to remember the reader" in offering written communications. Until an engineer accomplishes some outstanding work, his job performance is known only by his writing in the form of letters, articles and reports. No one can prepare an effective communication involving engineering analyses without a full regard for the problem the recipient of the communication will face in understanding what is intended to be transmitted.

Presenting Conclusions

Every communication is for the purpose of imparting one individual's conclusions to another. John Mills in his book[1] deals very effectively with the problem of this personal quality in an engineer. He calls attention to the fact that scientists and engineers by natural tendency reason from cause to effect, and in so doing, they stress similarities between situations in arriving at conclusions. Executives are not scientists and do not think in terms of similarities. Their's is not the cause to effect process of reasoning. The executive must spend his time choosing between differences; between consequences of courses of action. The executive responsibility is directed almost always to the question, "What's the difference?"

When an engineer is asked to present recommendations, the tendency is too common for the engineer to invite the executive to run through the entire mental process used in deducing the conclusions respecting the situation. This is an exceedingly dangerous and ineffective procedure. The executives, not trained to reason from cause to effect, often lose patience with the engineer who insists that they adopt his procedure in arriving at a decision. The net

result of the usual approach is loss of attention on the part of the executive or loss of respect for the engineer. When the responsibility for drawing conclusions and recommendations rests with the engineer, the executive may, if he is forced to rehearse the entire procedure before receiving the answer, conclude that the engineer is incapable of reaching a decision and desires to place upon him the responsibility for drawing the engineering conclusion from the assembled analysis of the facts. If one is, by reason of job responsibility, required to think in terms of differences, then engineering reports should be rendered in terms of differences or in terms of consequences of different courses of action.

The Almighty Answer

A fourth personal quality that the educational process must develop is respect for the opinions and attitudes of others. Consistent with a natural tendency to be an individualist, the average engineering graduate has an unearthly high respect for his own answers to any problem. That undesirable personal characteristic must come from the use of text books with "answers." After a period of eight years of training to solve problems wherein the answer obtained is always verified by the "correct answer" in the back of the book, it is not unusual for a student to acquire the opinion that he has developed an infallible power to derive the correct and only answer to any stated problem. The ability to get the answer given in the book might be quite helpful in the educational process in that it builds up the student's confidence in his own work. It is, however, poor preparation for that time in his professional life when problems will not be formalized and are of such nature that the answer will not exist until he derives it. Some interesting situations develop in the citizenship of industry when two engineers derive different answers, or when one fails to carry the numerical result out to the same number of decimal places that another might have. Engineers must hate error. Engineers must always regard an "incorrect" answer as the cardinal sin. Yet, in the answer-getting process in industry there is need for the development of those principles of human relationship whereby differences in conclusion can be composed without loss of pride or professional standing, with recognition that the partners in a joint effort are all dedicated to an effort to find the really correct conclusion.

In Conclusion

The viewpoint expressed here is not intended to challenge the value of an academic degree in petroleum engineering. Rather, it is directed to an appraisal of the result produced by an attempt too early in the educational process to develop a professional skill at a sacrifice to the general objectives of a higher education and a more thorough study and understanding of the fundamental basis upon which a specialized skill must be built. Engineering education, like any other professional education, involves a learning process extending over a long period of years. There must be training of intellect and aptitude that lies distinctly within the province of the university as well as training in the industrial art to which engineering knowledge is to be applied professionally. The educational process is too extensive to be accomplished entirely by the time of graduation from the university. It must extend beyond that point. Industry is leaning more to the opinion that the most effective method for training petroleum engineers would be for the university to complete the basic training in engineering and citizenship with proper emphasis on the development of the personal qualities required of successful engineers.

A graduate's potential fitness for professional engineering is based more upon his knowledge of what constitutes engineering

and upon his ability to make himself understood than it is upon his possessing a certificate certifying to a particular aptitude in a specialized application of engineering. In the final analysis, it is difficult to distinguish basically the problems to be encountered by petroleum engineers from the problems that engineers encounter in any other industrial activity. If, through experience in an industry, an engineer develops special or exceptional ability to solve problems, that ability derives more from experience based upon a developed capacity in engineering than it derives from an election in his college term to follow a particular specialty. This viewpoint is based upon the conception that an engineer is not called upon to solve *a* problem but to solve problems. If the educational process were more definitely segregated as between the university and industry, then the failures that result from the lack of objectivity and the immaturity of the student in electing to follow a specialized course would be eliminated.

References

1. John Mills: The Engineer in Society. 1946. D. Van Nostrand Co., Inc.
2. Engineers' Joint Council: Employer Practice Regarding Engineering Graduates. *Min. and Met.* (April 1947) 197.
3. T. A. Rickard: Technical Writing. (Published for the Seeley W. Mudd Fund of the AIME.) 1931, New York. McGraw-Hill Book Co., Inc.

DISCUSSION

Donald L. Katz*—I wish to express my appreciation to Mr. Kaveler for preparing this paper. He is to be commended for his breadth of view and willingness to speak frankly.

A discussion of the term "applied courses" seems in order. I believe that engineering is the application of the pure sciences for the benefit of mankind. If we interpreted literally the suggestion that applied courses be excluded from the curriculum, it would mean the discontinuance of engineering education. There is a definition of "applied" and "fundamental" courses, however, which I would like to present to furnish a distinction between undesirable and desirable courses in petroleum engineering.

Fundamental courses are based on the sciences of mathematics, physics, chemistry and geology. Teaching consists of imparting knowledge of experimental facts and rational interpretations or theories relating the facts. Such a procedure shows the information which is lacking for a complete understanding of processes, materials, and situations which are encountered in the petroleum industry. The clumination of teaching is the search for the missing facts and when new data are obtained, the use of such for further interpretations. For example, in the field of phase behavior of oil and gas mixtures, the physicists and physical chemists developed in the period 1880 to 1905 most of the principles used today. However certain facts involving hydrocarbon systems were absent and we, the engineers, proceed to obtain the data and apply them in industry. One could say that phase behavior is applied physics but that is not the distinctive feature which makes its teaching acceptable as part of petroleum engineering. The criterion for deciding whether the material is fundamental is the method of teaching as well as the subject matter. The impression must be given that new problems can be solved by use of known data and theories just as successfully as previous solutions have been made. The objective then is to train the student to use his mind in application of scientific laws to everyday problems. This emphasis in teaching is the reason why most schools include original research and professional activity as a prerequisite for full professional status.

Applied courses which should be excluded from the curriculum are those which describe processes or situations as having finality. The emphasis of "how" instead of "why" does not give the young engineer the power to handle new problems. The training to perfection in the performance of processes and calculations does not assure understanding. The presentation of industrial operations to students is worthwhile only as background for orienting him in the utilization of the sciences for useful purposes.

Relative to developing the ability for oral and written expression, I believe that the only chance of improvement is for engineering

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instructors to insist on high standards of expression in their classes.

H. H. Power*—It is encouraging to find that a member from industry exhibits sufficient interest in petroleum engineering education to write a paper which should merit our serious consideration. Several years ago a section on education was established in this Division and an attempt was made to answer questions such as those proposed by Mr. Kaveler. Most of the schools of this country responded to questionnaires submitted and although complete accord has not been reached, yet a better understanding concerning petroleum engineering curricula and the role of the specialized courses has been attained. Other questionnaires were submitted to industry and the replies received, as related to the matters under discussion, were summarized aptly by several engineers and executives of recognized ability. Of particular interest is this question:

What are the specialized course requirements, that is, the content of the specialized petroleum engineering curricula? What is the recognized source material for teaching? What teaching methods should be employed? What additional requirements should be demanded of our teachers in these courses?

Mr. D. B. Collins (now deceased), of the Shell Oil Co., replied:

"These are extremely difficult questions to answer, and can only be answered after certain definitions are agreed upon. It is the writer's general opinion that in most cases only specialized courses should be given after completion of the usual four-year course of study. The most common lines of specialization are those of reservoir studies (including valuation), and subsurface specialists who are at heart geologists with a knowledge of economics and production methods. The source material of teaching should be the basic theories which are involved in the exploitation of oil fields and the teaching of these subjects should be the same as that employed in other academic subjects. The requirement that we should demand of our teachers in specialized courses is that they should know what they are talking about."

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Mr. John R. Suman, of the Humble Oil and Refining Co., said:

"Specialized courses for petroleum engineering for a four-year course should be limited to lecture work, teaching the application of basic scientific courses to problems dealing with the development and production of petroleum. It is thought that in the five-year course additional emphasis could be given to the application of fundamental courses in production problems. In lieu of laboratory courses it is believed that field courses during the summer vacation between the junior and senior years are more effective. It is also suggested that a supervised field trip be conducted during the Junior year to familiarize the student with general oil field conditions."

A. C. Rubel, of the Union Oil Co., replied:

"Specialized courses should be given in the highly specialized subjects, and I believe any school makes a mistake by attempting to give too many such courses. I believe, in Texas, for example, where there is a great interest in condensate pools under unit operation, that highly specialized courses in reservoir behavior under these conditions would be helpful. These courses would include all of the science and technique which has been developed, to solve these problems. In Colorado and Nevada much interest is being manifested in the recovery of oil from shale and bituminous coals, and this would offer a field of highly developed specialization in those areas. In the East, Penn State, . . . is doing a splendid job in secondary recovery.

"There is danger, I believe, in specialization of this sort unless the curricula and the teachers themselves keep currently abreast of the industry.

"The greatest need, in my opinion, in the educational field, as it applies to engineering, and particularly to petroleum engineering, is intimate contact with industry. Advancements are coming so rapidly and techniques are changing so frequently that a text book or even a formal lecture course can be badly out-of-date before it is put to use. I believe the most satisfactory way to accomplish this situation is to effect with industry an exchange of personnel at frequent intervals so that faculty may have practical experience and technical men in

industry may have opportunities to review and supplement academic training. In addition, I think it would be not only feasible but extremely welcome to industry to arrange for lecture courses and seminar work, using outstanding men in the industry who would be glad to give the necessary time."

At the meeting of the Educational Division, AIME, held in New York February 1947, Mr. P. H. Bohart, of the Gulf Oil Corporation, requested me to read his paper: "What Does Industry Have a Right to Expect of Petroleum Engineering Schools?"[4] After discussing the increased number of petroleum engineers in industry as compared with other branches of engineering, the diversity of the work required of the petroleum engineering, and the ever expanding problems of the future, Mr. Bohart has this to say:

"Does not the industry . . . have the right to expect the petroleum engineering schools to provide a broad basic training and a social and economic orientation which goes beyond merely supplying the minimum technical qualifications necessary to obtain a job or discharge the responsibilities of a particular job? If our system of free private enterprise is sound—and no industry better than the petroleum industry illustrates its soundness—is it not vital that petroleum engineers understand the philosophy of this type of economy? Such, obviously, is necessary and it is also necessary that these students be well grounded in the history of the oil business in the United States and in foreign countries so they may understand the industry and why it has progressed in the last thirty to thirty-five years almost with the speed of an explosion. They are entitled to a clear knowledge of the environment into which they are graduating.

"The petroleum industry must be considered as made up of not only the producers, refiners, and marketers, but also the service companies, contractors and manufacturers of oil-field equipment, besides the many individuals who buy leases and drill wells, and the consulting engineers, geologists, and geophysicists. In designing a course of study it is impossible to anticipate the specific job requirements of each of the many branches of the industry just as it is impossible to foresee the ultimate nitch into which each petroleum engineering graduate will fit himself. It seems apparent, therefore, that the emphasis must be placed on fundamentals and that the student must receive as broad a course as possible so that he will find himself reasonably well equipped wherever he may start and wherever fate and his particular talents may take him. The industry will always have openings for a relatively small number of specialists trained for highly technical work, but by far the greatest number of technically-trained personnel absorbed each year must "specialize on the job." The industry has the right to expect these people to come to it prepared in a way which will permit the greatest possible latitude and flexibility in molding them into efficient members of its complex organization. Working from a broad foundation of well-taught fundamentals, the individual can take full advantage of industry's "on-the-job specialization" and grow in the direction of his maturing tastes and talents.

" . . . It is not necessary that a graduate petroleum engineer know what a sucker rod is, but it is very necessary that he know something about thread design and stresses, and something about iron and steel and alloys. It is not necessary for him to know how to make a material balance computation but very necessary that he be thoroughly grounded in mathematics and physics. He should be thoroughly grounded in English, both written and spoken . . . Certainly there is little time during the standard four-year course to crowd in very many of the so-called 'descriptive' courses . . . without sacrificing some of the fundamentals, particularly if there is to be included in the four-year course the necessary instruction in auxiliary cultural and social-science courses such as psychology, history, economics and even industrial relations and public speaking . . .

" . . . With sufficient time at their disposal, it is easy enough for the petroleum engineering schools to provide the necessary basic training to meet any given set of what might be termed 'tangible requirements,' but probably it is not easy to provide the necessary background and environment to develop the philosophy, ethical standards, and the habit of using the 'engi-

[4] P. H. Bohart: What Does Industry Have a Right to Expect of Petroleum Engineering Schools. AIME *Petr. Tech.* TP 2270 (Nov. 1947); *Trans.* (1948) **174**, 325.

neering method' which engineers should have, because these cannot be given in specific three or four hour courses. Nevertheless, this training in the intangible requirements is something in which industry is deeply interested. The approach to an engineering problem, the engineering method, requires close and accurate observation, complete collection of facts, logical analysis, synthesis of pertinent data, and decision. It will be invaluable to them and their employers if engineers acquire in college the faculty and habit of applying this procedure—too many do not.

" . . . industry has the right to expect petroleum engineering schools to supply to their students inspiration and inspiring leadership . . . the industry has a right to expect the petroleum engineering schools to reduce to a minimum the number of potential 'drones' they graduate."

Personally, I shall welcome anyone interested in such matters to the University of Texas. The problem is not so much concerned with technical difficulties—well trained specialists can always be hired for university faculties—but the real problems are the selection of proper course material and the presentation of such material so as to achieve that initial but important step to the eventual engineering approach in all of its broadest aspects.

In conclusion, the student in petroleum engineering must have sound preparation in basic fundamentals. He must be able to analyze his problems quantitatively and recognize, separately, the various elements involved. He must know what qualities go to make up engineering judgment; that is, skill in reaching the best possible conclusion under the limitations of allotted time and required accuracy. He must appreciate the importance of cost and of practical economics. He must be able to organize his thoughts and to express them clearly through speech and written English. He must be willing and able to adjust his personality to his environment. Finally, he must have a decided interest in continued professional development, and a sound philosophy of social values.

G. M. Stearns*—Mr. Kaveler's paper represents a comprehensive discourse on a subject that has been discussed quite at length during the past few years by both educators and industrialists in formal conferences as well as in informal "bull sessions."

Mr. Kaveler expresses no general thoughts with which I disagree in principle, but it seems that some of his statements need additional qualification while other statements cause certain questions to arise in my mind.

Certainly the duty of the engineering college is to teach students fundamental subject matter and leave the "applied" engineering to be taught by experience and industry. However, I think the borderline between fundamental and applied courses is rather "fuzzy," making it difficult to definitely classify subject matter in the two categories. In this connection it should be emphasized that, relatively speaking, petroleum engineering is barely past its infancy as a major subject. Possibly we should say, it is still in the adolescent and plastic stage of development. Certainly, it has not attained that hardened stature of adulthood represented by civil and mechanical engineering, for example. At birth the petroleum engineering curriculum was a hybrid. It represented about a four-way course between mechanical engineering, chemical engineering, civil engineering and geology. In those early stages the educator merely included with certain courses in the four fields mentioned some descriptive courses concerning oil field equipment and methods, and called the whole agglomeration "Petroleum Engineering."

However, since that time there has been a constant stream of new developments that can be more appropriately classified under the heading of "petroleum engineering" subject matter. For example, present techniques for core analysis involving measurement of normal permeability, effective permeability, relative permeability, and interstitial water content necessitate considerations characteristic only of the petroleum engineering curriculum.

Decline curve analysis and some of the other methods of estimating recoverable oil and gas reserves are peculiar to petroleum engineering and cannot rightfully be classified in other major fields of engineering. Refinements of age-old chemical and physical principles supplemented by field data and experimental laboratory observations have developed such complicated methods of analysis that the original physical and chemical laws are so altered and adapted as to be almost unrecog-

* Stanolind Oil and Gas Co., Tulsa, Okla.

nizable. Three-phase flow through porous media, although following in general the fundamental laws of physics, requires a lot of special knowledge and technique in making proper mathematical evaluations of flow phenomena.

Most of the items of subject matter that I have mentioned are commonly placed in a broad and constantly broadening field of knowledge commonly referred to as "Reservoir Engineering." I believe that this type of subject matter represents in a true sense petroleum engineering.

In essence what I have just tried to convey is the thought that as time passes more and more subject matter becomes developed to such a point that it is almost exclusively applicable to drilling and production operations and is fundamental in itself because it is based on special tests, experiments and circumstances representative only of situations found in oil and gas development and production. Therefore, this increases the scope of what may be classified "fundamentals" in petroleum engineering education.

I am sure that Mr. Kaveler recognizes the trend in petroleum technology which I have just mentioned. Furthermore, various colleges and universities have recognized such trend and are now making, or have already made, curriculum revisions to replace purely descriptive and applied courses with the relatively new fundamental courses.

As a member of the Petroleum Division of AIME, I point with pride to the fact that the papers and publications of this Institute form a substantial part of the fundamentals of petroleum engineering.

Particularly, I wish to agree with Mr. Kaveler concerning the value of wisely chosen summer employment by engineering students. Employment of this nature not only acts as a vocational guide in assisting an engineer in choosing a field of specialization, but also gives him a preview before it is too late of the importance of a firm foundation in certain fundamentals to which he is later to be exposed in college courses of junior and senior standing.

In discussing this subject one cannot avoid a few questions concerning whether a sufficient background of fundamental engineering knowledge can be obtained by the end of the fourth year of college. Therefore, I would like to offer the following questions as a basis for further discussion by Mr. Kaveler and other interested individuals.

What additional opportunities are available to the graduate of a five year course, or the recipient of a Master's or Doctor's degree?

What specialized phases of oil producing and drilling activity require that the engineers have an advanced degree?

Is an interim period in industry desirable before continuing college study to obtain an advanced degree?

CHAPTER VII. *Petroleum Economics*

Capital Formation in the Petroleum Industry

BY J. E. POGUE,* MEMBER AIME, AND F. G. COQUERON*

(New York Meeting February 1948)

ABSTRACT

THIS paper describes the sources of funds required by the petroleum industry to finance capital expenditures and also presents a discussion of the effect of rising construction costs on these expenditures. The petroleum industry obtains its capital funds from several sources: (1) internal, from retained cash earnings; and (2) external, from borrowings and the sale of securities to the public.

The upward trend of capital expenditures of the petroleum industry is caused in the main by the influence of two powerful factors: (1) the physical growth in the demand for oils; and (2) the rising cost of drilling wells and constructing refineries, pipe lines, and other facilities. The segregation of these factors is accomplished by deflating the actual capital expenditures so that they are shown in terms of 1939 costs and then subtracting the adjusted series from the actual figures to yield a set of data representing the expenditures made on account of higher costs.

Rising costs affect prices and the portion attributable to this factor had to be generated from the cash earnings of the industry, which called for higher oil prices.

INTRODUCTION

Capital may be defined as "wealth employed in or available for production." All production requires capital. Expanding industries require more capital than static ones, and technological industries employ more capital than those in which little equipment is needed. The petroleum industry is both rapidly growing and highly technological, and, being a large industry, its capital requirements are prodigious, amounting to about one-seventh of the total of all American business, excluding agriculture.*

Capital formation may be defined as the method by which the wealth or capital needed in the productive processes is created. There are various ways in which capital funds may be obtained but there is only one way in which capital can be created—out of production in excess of consumption, that is, savings. The physical realities are simple, but the monetary concepts are complicated because the mechanism of credit can draw upon future savings.

SOURCE OF CAPITAL FUNDS

An industry, such as the petroleum industry, can obtain its capital funds from

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* Vice President and Staff Associate, respectively, Petroleum Department, The Chase National Bank, New York, N. Y.

* The Economic Report of the President, Washington, January 1948, Table 19, estimates the 1947 expenditures of all American business (excluding agriculture) for new plant and equipment at 15.68 billion dollars. The 1947 capital expenditures for domestic facilities by the group of 30 oil companies amounted to 1.74 billion dollars. This figure, after excluding outlay for dry holes, indicates expenditures of 2.31 billion dollars for the entire American petroleum industry in the United States. The oil expenditures represent 14.7 pct of "all business."

several sources: (1) internal, from its retained cash earnings; and (2) external, from borrowings and from the sale of securities to the public. The internal source makes use of the industry's own savings. The external source draws upon the savings of others, which may be past, present or future (that is, enforced) savings. Obviously, the internal source should be predominant, for if no industry generated its own capital, there could be little capital formation. It follows, then, that the higher the degree of internal generation of capital, the sounder the industry financially and the greater its stabilizing influence upon the entire economy.

TABLE 1—*Trend of Capital Formation of 30 Oil Companies*, 1934 *to* 1947

Year	Cash Income from Earnings[a]	Preferred and Common Dividends Paid in Cash[b]	Balance Available for Capital Expenditures	Capital Expenditures[c]	Cash Income from Earnings in Excess of Capital Expenditures
	Million Dollars				
1934	616	128	488	461	27
1935	740	120	620	517	103
1936	922	234	688	634	54
1937	1,139	289	850	929	−79
1938	859	200	659	669	−10
1939	885	189	696	665	31
1940	957	209	748	657	91
1941	1,178	269	909	810	99
1942	1,017	238	779	786	−7
1943	1,210	260	950	931	19
1944	1,513	308	1,205	1,096	109
1945	1,647	311	1,336	1,116	220
1946	1,552	351	1,201	1,379	−178
1947 E	2,160	455	1,705	2,075	−370

E, Estimated.
[a] Net income plus noncash charges (capital extinguishments, income applicable to minority interests, provision for contingencies, and others).
[b] Includes dividends paid to minority interest stockholders.
[c] Represents investments in domestic and foreign facilities, including cost of dry holes. Excludes expenditures of a fixed capital nature represented by security investments in and advances to nonconsolidated subsidiaries and associated companies.

Internal Capital Formation

By means of a study of the combined operating and financial results of a group of 30 representative oil companies, as conducted by the Petroleum Department of the Chase National Bank* for the years 1934 to the present, it is possible to trace the processes of capital formation in a large segment of the petroleum industry and to portray its relationship to prices, costs and rates of expansion.

For the past 14 years, 1934 to 1947, the group of 30 oil companies has struck a close balance between the amount of capital expenditures and the amount of cash generated internally from net income retained after dividends and from noncash charges for depreciation, depletion, and the like. The record is shown in Table 1. It may be observed that in only three years of this period—1937, 1946 and 1947—did capital expenditures run materially ahead of the internal cash generated and available for such purposes. These figures do not mean that the group had recourse to the capital markets in only the three years mentioned, for the expansion of the companies required increasing amounts of working capital. The average growth in this item from 1939 to 1946, inclusive, has been 90 million dollars per year. In addition, the 30 oil companies have made fixed capital investments in nonconsolidated and associated companies during this period. In general, however, the petroleum industry has been able to generate most of its capital needs, with the favorable result that its borrowed capital is about one-eighth of the total capital employed.

In this process of capital formation, the 30 oil companies have been retaining a growing percentage of their net income for reinvestment. For example, in the five years, 1934 to 1938, the proportion of retention was 42.9 pct; in the five years, 1939 to 1943, the part plowed back was 48.2 pct; in the three years 1944 to 1946,

* See "Financial Analysis of Thirty Oil Companies for 1946," The Chase National Bank, pamphlet, August 1947, for data covering the years 1934 to 1946 and for names of the companies composing the group.

the percentage had risen to 54.6; and in 1947, approximately two-thirds, or 65.1 pct, is the estimated proportion of net income retained for reinvestment. The stockholder, therefore, has been making a growing contribution to the process.

External Funds

The funds raised by the 30 oil companies in the capital markets are analyzed in Table 2 for the three years, 1945 to 1947. A steady, though not marked, increase in the total raised is revealed, but since part of the new capital is employed to retire old capital, the net additions are limited though revealing a rise to 548 million dollars in 1947. It will be observed that in 1947 the gross borrowings declined from 1946, but there was a substantial recourse to equity financing in the amount of 206 million dollars, of which 177 million dollars was in the form of common stock and 29 million dollars, preferred stock. The borrowings of 476 million dollars were divided as follows: From banks, 63.2 pct; from insurance companies, 34.7; and from other sources, 2.1. The projected relationships of internal capital formation and capital expenditures suggest that the 30 oil companies in 1948 may not increase their demands upon the capital markets, but rather will probably supply a greater part of their needs from internal sources than in 1947.

Factor of Rising Costs

The upward trend in the capital expenditures of 30 oil companies is caused in the main by the influence of two powerful factors: (1) the physical growth in the demand for oil; and (2) the rising cost of drilling wells and constructing refineries, pipe lines, and other facilities. It would be of interest to segregate these two components. This separation may be approximately accomplished by deflating the actual expenditures so that they are shown in terms of 1939 costs and then subtracting the adjusted series from the actual figures to yield a set of figures representing the expenditures made on account of higher costs. The data and computations are shown in Table 3.

Observing the data for 1947, by way of example, it will be noted that the total capital expenditures of 2,075 million dollars are broken down into two parts; 887 million dollars representing expenditures expressed in 1939 costs, and 1188 million dollars representing expenditures incurred because of the rise in costs from the 1939 level. It thus appears that for each dollar expended in 1947 for facilities, 57.3¢ went

TABLE 2—*Analysis of Capital Raised from External Sources by 30 Oil Companies, 1945 to 1947*

Year	Borrowings	Preferred and Common Stock Issued	Sale of Fixed Assets and Other Transactions	Total New Capital	Long-term Debt Retired	Preferred Stock Redeemed	Net New Capital Acquired
	Million Dollars						
1945	408	81	37	526	413	70	43
1946	586	21	15	622	461	9	152
1947 E	476[a]	206[b]	63	745	197	0	548

E, Partly estimated.

[a] Analysis of borrowings from:

	Million Dollars	Per Cent of Total
Banks	301	63.2
Insurance companies	165	34.7
Public investors	0	0.0
Others	10	2.1
Total	476	100.0

[b] Preferred stock, 29 million dollars; and common stock, 177 million dollars.

to cover *increased costs.* Accordingly the 30 oil companies spent a base amount of 887 million dollars and an extra amount of 1188 million dollars to cover the rise in costs.

We thus see how rising costs affect prices, for obviously this additional sum had to come mainly from the cash earnings of the industry, which called for higher oil prices. This expenditure on account of higher costs represents 68¢ per barrel of crude oil processed in 1947 by the group. In the same year the average price of 36 gravity crude oil averaged 52¢ higher than in 1946.

It is difficult to find a satisfactory cost index with which to deflate capital expenditures to a basis of 1939 costs. None exists in the petroleum industry itself, and the industry's rise in costs is complicated by the presence of technological factors such as deeper drilling, more complicated refinery equipment, and the like. The American Appraisal Co. publishes an index of construction costs in 30 American cities which has been selected as reasonably satisfactory (see Table 3). At first glance it might appear that this index shows a greater rise than is reasonable for oil. But a careful comparison with specific cost changes in oil facilities suggests that this index when applied to oil industry expenditures does not overstate the cost factor. Moreover the Petroleum Department's index of per-well drilling costs indicates for the years covered a greater rise than the American Appraisal Company's index.* Therefore, the index used in our computation probably throws back into the base figures part of the higher costs resulting from technological changes.

TABLE 3—*Capital Investments of* 30 *Oil Companies Segregated into Expenditures on Basis of* 1939 *Costs and Expenditures Caused by Rise in Construction Costs,* 1939 *to* 1947

Year	Capital Expenditures of 30 Oil Companies, Million Dollars	Index of Construction Costs in 30 Cities,[a] 1939 = 100	Capital Expenditures Expressed in 1939 Costs, Million Dollars 1 ÷ 2	Indicated Expenditures Absorbed by Rise in Construction Costs, Million Dollars 1 − 3	Expenditures Represented by Rise in Construction Costs, Per Cent
1939	665	100	665	0	0.0
1940	657	112	587	70	10.7
1941	810	119	681	129	15.9
1942	786	132	595	191	24.3
1943	931	138	675	256	27.5
1944	1,096	143	766	330	30.1
1945	1,116	148	754	362	32.4
1946	1,379	176	784	595	43.1
1947 E	2,075	234	887	1,188	57.3

E, Partly estimated.
[a] Source: American Appraisal Co.

RELATION TO EXPANSION

Considering next the deflated capital expenditures of the 30 oil companies, which reflect mainly the element of physical growth, this series is compared in Table 4 with the crude oil processed. It may be observed that the deflated expenditures have not expanded as rapidly as the volume handled. Expressed in terms of dollars per barrel of crude-run-to-stills, the figures show that the deflated expenditures per barrel have followed a downward drift from 58¢ per barrel in 1939 to 48¢ per barrel in 1945 and 1946, while the expenditures on account of higher costs show a marked rise in 1946 and 1947, amounting to 68¢ per barrel in the latter year. Any decline in costs would release funds for expenditures for growth, which has recently been re-

* Source	1939	1940	1941	1942	1943	1944	1945	1946
American Appraisal Co.:								
Index of Construction Costs	100	112	119	132	138	143	148	176
Petroleum Department:								
Index of Drilling Costs per Well	100	107	101	116	143	159	215	217

tarded by shortages of steel and other materials.

Relation to Price

If we assume that: (1) the present price of 36 gravity Mid-Continent crude oil will represent the average for 1948, (2) the American Appraisal Company's Index of Construction Costs will average 251 for

Table 4—*Capital Expenditures of 30 Oil Companies, Actual and Deflated Cost Expressed in Dollars per Barrel of Crude Processed*, 1939 *to* 1947

Year	Capital Expenditures, Million Dollars		Crude Run to Stills, Million Barrels	Capital Expenditures, Dollars per Barrel		
	Actual	In 1939 Costs		Actual	In 1939 Costs	Difference Due to Rising Costs
1939	665	665	1,141	0.58	0.58	0.00
1940	657	587	1,166	0.56	0.50	0.06
1941	810	681	1,283	0.63	0.53	0.10
1942	786	595	1,170	0.67	0.51	0.16
1943	931	675	1,316	0.71	0.51	0.20
1944	1,096	766	1,526	0.72	0.50	0.22
1945	1,116	754	1,562	0.71	0.48	0.23
1946	1,379	784	1,621	0.85	0.48	0.37
1947 E	2,075	887	1,741	1.19	0.51	0.68

E, Partly estimated.

the year (approximately the level of December 1947), (3) the 1948 capital expenditures of 30 oil companies will amount to 2300 million dollars, and (4) the volume of oil processed by the group will increase 8.0 pct, there is afforded the basis for an interesting approximation; namely, that the present price of $2.57 per barrel for 36 gravity crude oil may be segregated into two components,* as follows:

Result of rise in costs from 1939 level	$0.74
Result of other factors	1.83
Total price	$2.57

Therefore it would appear that something like 74¢ per barrel of the current price of crude oil is the result of higher costs involved in capital expenditures.

Conclusions

This study leads to five broad conclusions:

1. The petroleum industry generates out of its own operations most of the capital required for its expansion and is a leading industry in the process of capital formation.

2. The petroleum industry has been retaining a growing share of its net income for reinvestment, the proportion having reached 65.1 pct in 1947.

3. The petroleum industry will be able to finance its capital requirements for 1948 largely out of its internal capital formation, with an expected smaller recourse to capital markets than in 1947.

4. Of the 1947 capital expenditures of 30 oil companies aggregating 2.07 billion dollars, 57 pct, or approximately 1.19 billion dollars, represent expenditures resulting from the rise in construction costs from the 1939 level, including some technological changes such as deeper drilling.

5. Of the current price for 36 gravity Mid-Continent crude oil of $2.57 per barrel, we estimate that 74¢, or 28.8 pct, represents the component of the price reflecting the rise in construction and technological costs from the 1939 level, while $1.83 represents the part of the price resulting from other factors.

* Calculation: E = Estimated capital expenditures of 30 oil companies, 2300 million dollars.
C = Estimated index of construction costs, 251.
P = Price of 36 gravity Mid-Continent crude, $2.57 per barrel.
R = Estimated runs to stills of 30 oil companies, 1880 million barrels.
X = Component of crude oil price represented by rise in construction costs from 1939 level.

$$X = \frac{E - \left(\frac{E}{C} \times 100\right)}{R} = \$0.74$$

$$P - X = \$1.83$$

INDEX

(NOTE: In this index the names of authors of papers and discussions and of men referred to are printed in SMALL CAPITALS, and the titles of papers in *italics*.)

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